Generation-Technical

Memorandum to the
Royal Commission on
Electric Power Planning
with respect to the
Public Information Hearings

GENERATION - TECHNICAL

Submission of

ONTARIO HYDRO

to the

Royal Commission

On Electric Power Planning

with respect to the

Public Information Hearings

March, 1976

2. GENERATION: Scientific and Technological Developments and Environmental Health and Safety Factors

Introduction

VOLUME 1

2.1 NUCLEAR GENERATION

2.2 GENERATION, FOSSIL AND OTHER TYPES

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List of Short Forms

AECB	- Atomic Energy Control Board
AECL	- Atomic Energy of Canada Limited
AGR	- Advanced Gas-Cooled Reactor
Btu/hr	- British thermal units per hour
Btu/kW	- British thermal units per kilowatt
BLW	- Boiling Light Water
BLW(PB)	- Boiling Light Water (Plutonium Burner)
BWR	- Boiling Water Reactor
CANDU	- Canadian Deuterium Uranium
CFS	- Cubic feet per second
CO_2	- Carbon dioxide
FBR	- Fast Breeder Reactor
GCFR	- Gas Cooled Fast Breeder Reactor
HTGR	- High Temperature Gas-Cooled Reactor
km^2	- square kilometres
LMFBR	- Liquid Metal Cooled Fast Breeder Reactor
LWBR	- Light Water Breeder Reactor
LWR	- Light Water Reactor
m^3	- cubic metres
MPa	- Megapascals
MSBR	- Molten Salt Breeder Reactor
MWD/TeU	- Megawatt Days per tonne (metric) of Uranium
MWe	- Megawatts electrical
MWh	- Megawatt hours
MWt	- Megawatts thermal
OCR	- Organic Cooled Reactor
PHW	- Pressurized Heavy Water
psi	- pounds per square inch
psia	- pounds per square inch absolute
PWR	- Pressurized Water Reactor
SGHWR	- Steam Generating Heavy Water Reactor
SO_2	- Sodium dioxide
THTR	- Thorium High Temperature Reactor
UO_2	- Uranium dioxide
U_3O_8	- Uranium oxide (yellowcake)
USGPM	- United States gallons per Minute
^oC	- Degrees Celcius
^oF	- Degrees Fahrenheit
$/kWe	- Dollars per kilowatt electrical

2 GENERATION: Scientific and Technological Developments and Environmental Health and Safety Factors

Introduction

It may be appropriate to introduce this section on electricity generation technology by stating a few of the characteristics of electricity and the electrical utility business.

Electricity does not occur in nature in a useable form - it must be produced or "generated" from other sources of energy. The electrical utility has no product inventory since electricity cannot be stored in significant quantities. It is generated a fraction of a second before it is used and is transmitted over large distances virtually instantaneously.

The utility is committed to supplying all connected loads regardless of the magnitude or rate of change of the demand for electricity. The demand is changing constantly and may differ by a factor of two within about an hour.

The quality of our product is measured by the constancy of the power frequency and voltage, and the continuity of supply, all of which are fundamental aspects of generation technology. Continuity of electrical service depends on many factors uncluding: primary energy resources, reliability of the generation and transmission system and disposition and nature and magnitude of loads and operating plant.

In a review of technology applicable for generation of electricity for Ontario it is necessary to have an understanding of the time period under consideration and the future circumstances in the province.

The information presented in this brief is based on a period from the present to about 30 years in the future. The time between the start of planning - approval stages to in-service of a proven design of a large electricity generating station on an existing site is about 10 years. If new technologies are involved and pilot or demonstration stations are required before useful quantities of electricity can be generated, 20 or more years may be required. This means that our present conceptual

and preliminary engineering activities are directed at the needs 10 to 20 years in the future. Although some consideration should be and is given to generation technology beyond 30 years in the future, it must be borne in mind that developments in the energy field in the next 15 or 20 years will add significantly to alternatives available for the more distant future.

In the next 30 years it is assumed that Ontario will remain in the front rank in Canada as a centre of industry and manufacturing, and that the population will continue to grow, in line with that of the rest of Canada, albeit at a somewhat slower rate than in the past. It is expected that the provincial population will be about 12 million by the turn of the century.

The indigenous primary energy resources within the Province of Ontario which can be harnessed to meet the energy needs of the industries and citizens in the province in the next 30 years are very limited. At the present time Ontario depends on sources outside the Province for over 80 percent of the energy consumed; mainly gas and oil from Western Canada and coal from the United States. In these times of rapidly depleting fossil fuels and escalating fuel costs the security of supply of primary energy is of vital concern in considering the future generation of electricity. Just to maintain the present position of the provincial economy, let alone grow as expected, will require vast additional quantities of primary energy even with the best efforts at energy conservation.

Ontario was fortunate in having excellent hydraulic resources near the point of need and over the years these have been employed for both mechanical work and generation of electricity. At the present time most (approximately 60%) of the hydraulic resources in the southern part of the province are being used for the generation of electricity. The remaining resources are either small or intermittent and would be costly to develop, and/or prized for their aesthetic value and natural beauty (e.g. Niagara Falls and Niagara River rapids). The remaining hydraulic resources in the northern part of the province, if developed, could add about 50 percent to the electrical energy being generated hydraulicly in the province. However, these are difficult and costly sites to develop and would require long

transmission systems to deliver the energy to the point of need.

There are no known significant hydrocarbon resources in the province - very small amounts of oil and gas in southern areas and a relatively small lignite deposit near James Bay. However, there are extensive deposits of uranium and thorium and a base of experience and knowledge in design and construction and operation of nuclear generating stations which can produce electrical energy at a cost lower than that from the most modern fossil fired station.

In an assessment of electrical generation technologies for future use in the province the following factors are considered to be of prime importance:

1. Public Safety
2. Security of primary energy
3. Capital requirements and product cost
4. Environmental effects of generation - effects on air and water quality and land use
5. Conservation of energy - particularly the scarce hydro-carbon resources
6. Experience and capability and "know how" to provide a dependable electrical supply

Ontario Hydro's assessment of the alternatives for generation which are discussed in this brief, has led to the conclusion that the best choice to supply the major electrical energy needs for the province in the next 30 years is the Candu nuclear system which has outstanding safety features. The resource of uranium within the province, the product cost, environmental effects, fossil fuel conservation and capability to provide dependable electrical supply all appear to support this position.

The most economic arrangement for generation of electricity in the future would appear to be in the form of large multi-unit generating stations similar to the ones now being installed, with perhaps larger units, located adjacent to the Great Lakes on interconnecting rivers for cooling and access. The Great Lakes system, with their enormous capacity for cooling is an important resource in converting heat to electricity and provides both energy conservation and cost advantages in the production of electricity for the province.

As we see it none of the new technologies based on renewable resources, (solar, wind, tides, geothermal, etc.) are likely to be of major significance in the generation of electricity or for that matter any managed form of energy in the next 30 years in the Province of Ontario due to present high costs and difficult developmental potential. However, solar energy for space heating using heat pumps or by direct thermal means may displace some of the fossil fuel consumption in space heating in the period.

In the longer term there appears to be a need to supplement fuel resources for the Candu system. In addition to acquisition of and exploration for uranium resources it is proposed to develop in collaboration with Atomic Energy of Canada Limited the advanced fuel systems which involve plutonium recycle and the use of thorium.

These conclusions will be discussed further in the main hearings to be held by the Royal Commission.

The following information on nuclear, and fossil generation technology and related environmental effects consist of brief summaries on each topic followed by a list of references and pertinent documentation.

Line Number

2.1 NUCLEAR GENERATION

2.1.1 Nuclear Generating Station Types

All types of present-day power reactors have the basic principle of using heat which is produced by fission of heavy atoms to produce steam for a conventional turbine-generator. There have been at least a dozen reactor concepts proposed over the years using this basic concept, but each with unique design features. Only two or three of these have survived the tests of engineering feasibility and economic competition and are now at the stage of full commercial application. These are:

(a) the pressurized water reactor (PWR)
(b) the boiling water reactor (BWR)
(c) the pressurized heavy water cooled, heavy water moderated, natural uranium reactor (CANDU-PHW).

2.1.1.1 The CANDU Power System(1,2,3,4,5,6,7,8,9)

The name CANDU refers to a type of nuclear reactor which has been developed in Canada over the past 25 years. The commercially-available Canadian design is referred to as the CANDU-PHW. This identifies a reactor with heavy water as both coolant and moderator as shown in Figure 2.1.1-1. (CANDU-PHW is derived from Canadian Deuterium Uranium-Pressurized Heavy Water). The moderator is contained in a low pressure tank through which 400-500 calandria tubes are passed. Pressure tubes about 10 cms in diameter are fitted inside the calandria tubes and uranium oxide fuel bundles similar to the one shown on Figure 2.1.1-2 are placed inside the pressure tubes. The pressure tubes form part of a closed circuit filled with heavy water under high pressure (about 11 MPa). Pumps and steam generators are also in this circuit. The high pressure heavy water is used to transport heat from the fuel to the steam generator, where it is transferred to ordinary water in a second closed circuit consisting of the turbine, condenser, and feedwater heating system. Steam expansion in the turbine transfers energy to rotary motion of the generator shaft. The condenser receives the expanded steam at very low pressure and removes heat to condense the steam. This condensation is necessary so that the loop can be closed by pumping water back to the steam generator. Heat extracted during condensation is transferred to the station cooling

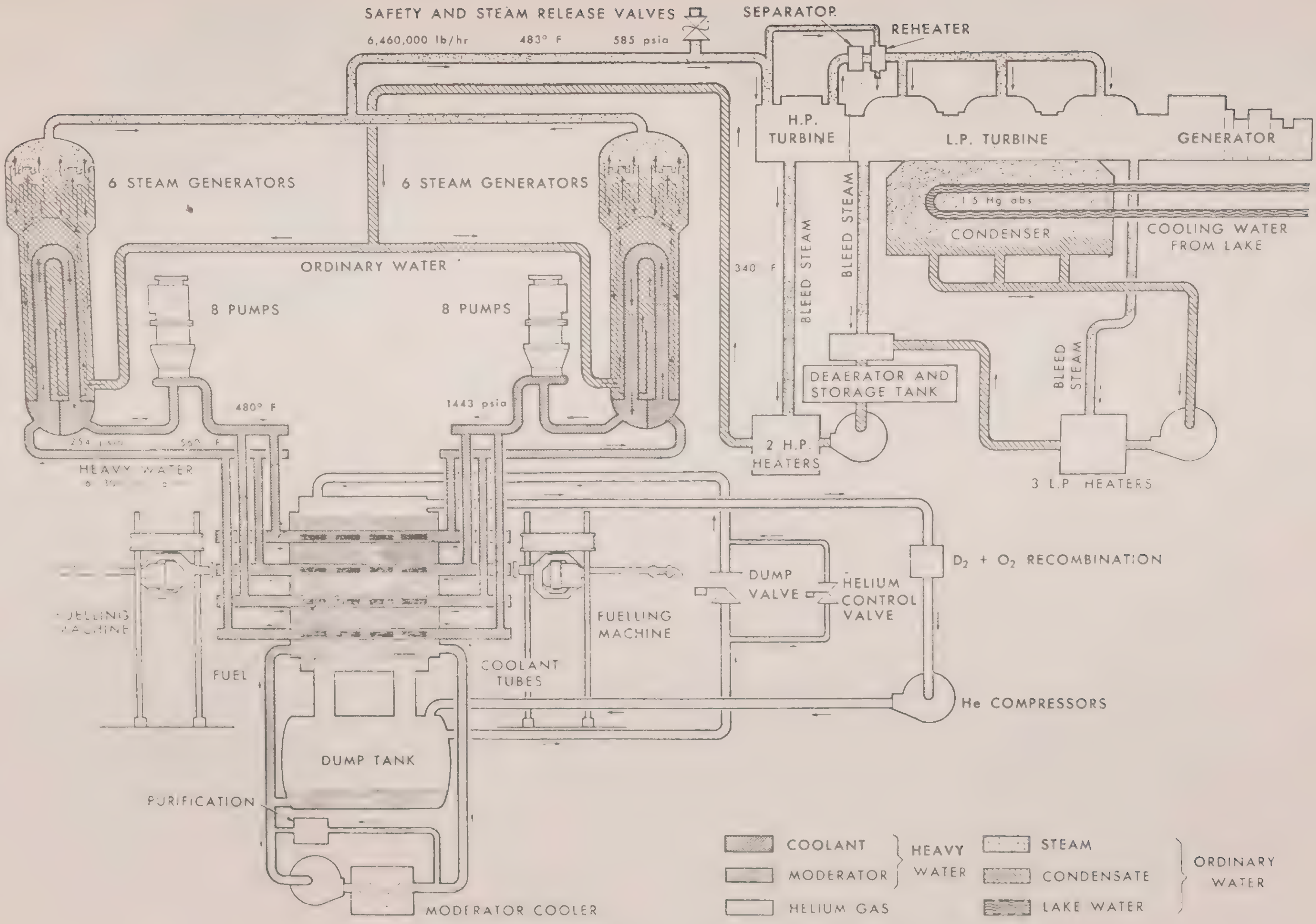

FIGURE 2.1.1–1 SIMPLIFIED STATION FLOW DIAGRAM
OF A CANDU (PHW)

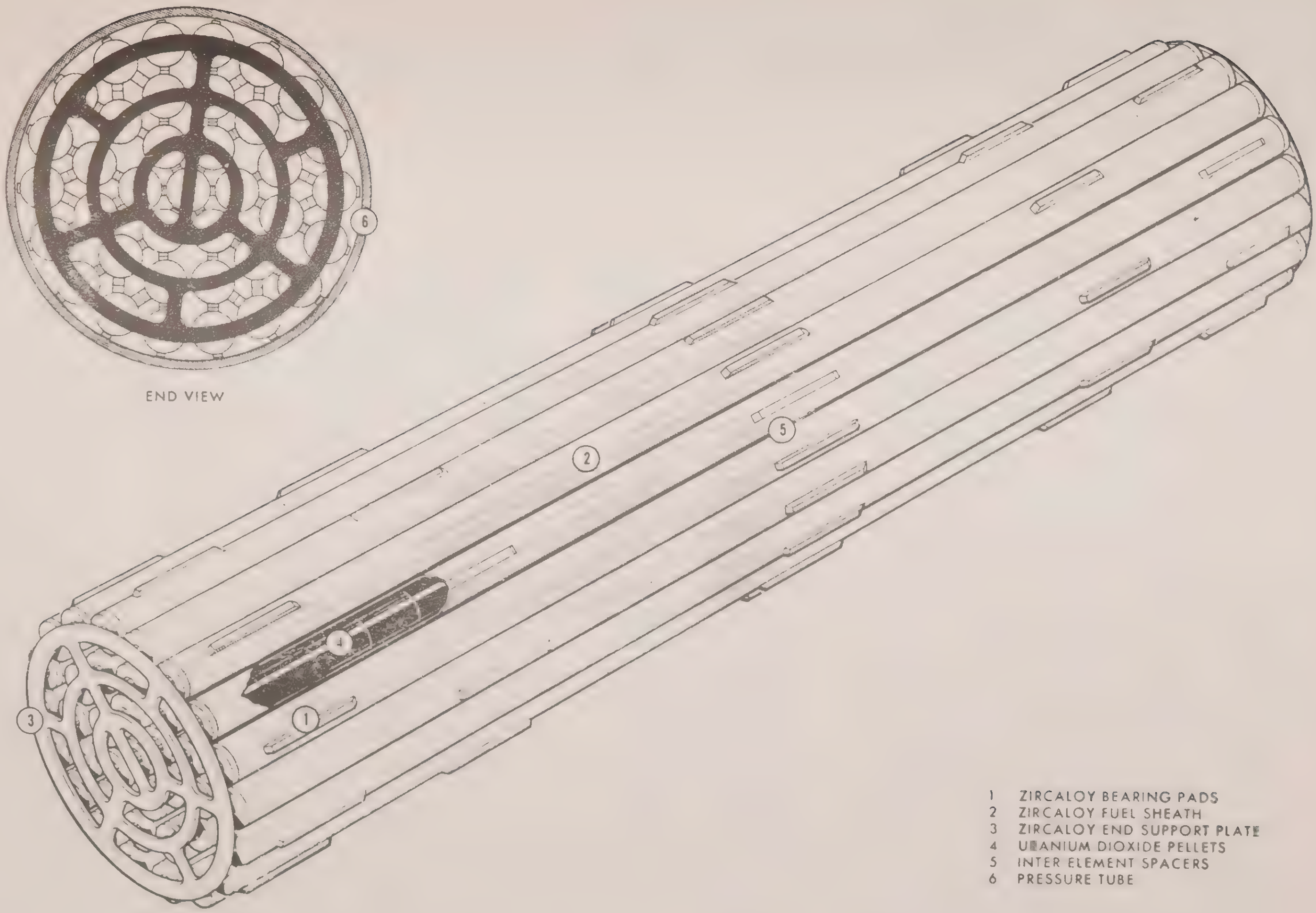

FIGURE 2.1.1–2 FUEL BUNDLE FOR A CANDU (PHW)

water and rejected. The thermal efficiency of the CANDU-PHW system is about 30 per cent.

The CANDU-PHW is characterized by low-cost fuelling (natural uranium dioxide), expensive moderator and coolant (heavy water), and relatively high capital cost. The use of heavy water is justified because of its very low neutron absorption rate. This permits use of natural uranium fuel instead of expensive enriched fuel. The capital cost is influenced by materials limitations which lead to quite low steam temperatures and by the fact that the initial inventory of heavy water is included in the capital charge. Fuel costs, on the other hand, are lower than those of any other reactor system presently available. The fuel burnup obtained is about 7,500 MWd/TeU.

Partly because of the ability to change fuel with the reactor at high power, and partly because of high quality in design and manufacture, high capacity factors are achievable with the system. Resource utilization in terms of electrical energy produced per tonne of mined uranium is better than that of any other reactor system currently available, but considerable improvement can be achieved by further development.

2.1.1.2 CANDU Experience (10,11,12,13)

The Canadian nuclear power program began with NPD-2, a 20 MWe demonstration plant which was placed in-service in October 1962. This plant was built as a cooperative project of Atomic Energy of Canada Ltd., Ontario Hydro, and Canadian General Electric. Its technology was based on Chalk River nuclear research. To date it has produced 1,462,000 MWh of electricity, equivalent to continuously maintaining 59.2 per cent of its design capacity. Recent performance has been considerably better; during 1975 the station operated at 74 per cent of design capacity. The reactor is used for training station staff and this leads to a lower capacity factor than would otherwise be attainable.

The next station in the development line was the prototype 220 MWe Douglas Point GS. This project was principally funded by AECL under an agreement with Ontario Hydro in which AECL designed the nuclear steam supply system and Hydro designed the balance of the plant and undertook the construction. Ontario

Hydro also agreed to operate the station and purchase the power. The station was placed in-service in September 1968. Early operating problems led to poor performance, but these difficulties have been resolved. To date the plant has produced 4,137,000 MWh of electricity and the steam equivalent of a further 1,985,000 MWh, which is 46.2 per cent of its design capacity. During 1975 it produced at 84 per cent of design capacity. The steam is being used to supply a heavy water production facility on the site.

The first full-scale commercial CANDU station, the 2,160 MWe Pickering GS, was committed in 1964. This is a 4-unit station; in-service dates for the units were July 1971, December 1971, June 1972 and June 1973. Up to the end of December 1975 it had delivered 44,831,000 MWh of electricity to the bulk power system at a capacity factor of 67.8 per cent. A 1972 strike during which three units were shut down reduced the capacity factor. This effect is included in the above figure, even though it cannot be charged against the station design. Another cause of significant loss in production during 1975 was the existence of cracks in some pressure tubes of units 3 and 4 due to improper installation. Routine manufacturer's turbine inspection and difficulties with turbine generator components also has had a very significant effect on the capacity factor of the station. Even with all these effects included the station performance compares favourably with world experience. Units 1 and 2 have ranked at the very top of annual capacity factors tabulated for all reactors in the world.

CANDU-PHW reactors are operating in Pakistan and India, but experience is difficult to interpret because the electrical loads demanded are highly variable in contrast with base-load operation of Ontario Hydro stations. The KANUPP station in Pakistan is of 137 MWe size; its capacity factor since in-service is 45 per cent. The RAPP-1 station has 220 MWe capacity; it also has a 45 per cent capacity factor since in-service.

The committed Ontario Hydro program consists of three new CANDU-PHW stations. Bruce A GS, with four units, will supply 3,000 MW of electricity and a further 400 MW equivalent in steam energy to the Bruce Heavy Water Plant. The first unit is scheduled to be in-service in 1976, with the other three following at 12-month intervals. Pickering B GS, a nominal duplicate of Pickering A, has a first unit in-service

date of 1981. Bruce B GS, a duplicate of Bruce A, is scheduled for first unit in-service in 1983. It is planned that two thirds of future new generation will be nuclear, and the nuclear generation will utilize the proven CANDU-PHW concept at least for the foreseeable future (14,15).

The economics of power reactors improve as the unit size increases. On a power grid, however, the largest units affect the reserve requirements and should not represent greater than a certain fraction (about 5 per cent) of the total installed capacity. In anticipation of continuing growth of the Ontario Hydro system, conceptual design is underway on a 4-unit station of 1,250 MWe units. Preliminary studies have been done by AECL on a 2,000 MWe unit.

Atomic Energy of Canada Ltd. has developed a standard CANDU-PHW unit of 600 MWe capacity, based on improvements to the Pickering units. This design is intended to provide utilities with a standard, modest sized unit, which can be installed in single or multiple unit stations. The station features are somewhat different than the 4-unit arrangement adopted by Ontario Hydro at, for example, Pickering or Bruce. Hydro Quebec and New Brunswick Power each have one unit under construction. Contracts have been signed for one unit in each of Argentina and Korea.

2.1.1.3 CANDU Concept Variations (15)

The CANDU-PHW reactor has a relatively high capital cost, partly due to the heavy water coolant and moderator, and partly because the turbine steam temperature (300°C) is relatively low. This temperature is controlled by two important factors. First, the "indirect" cycle uses steam generators to transfer heat from the primary coolant circuit to the secondary side steam system resulting in a large drop in temperature. Second, the primary circuit pressure (and hence its temperature) is restricted because of the need to maintain reasonable thickness of the pressure tubes in the reactor. Increasing pressure tube thickness decreases fuel burnup, resulting in poorer fuel economy.

Two variations of CANDU have been proposed which are intended to reduce costs and improve performance. Both of these concepts can be designed to use natural uranium fuel.

The first variant, a CANDU reactor with boiling light (ordinary) water as coolant, designated CANDU-BLW (16,17,18), utilizes a direct cycle, in which water is boiled in the reactor to produce steam directly for use in a turbine. No boiler is required, so that higher steam temperatures can be achieved. The difficulty of controlling heavy water leakage from high pressure circuits is eliminated. (See Figure 2.1.1-3).

The CANDU-BLW has reached the stage of an operating prototype, the 266 MWe Gentilly-1 station in Quebec. Gentilly-1 was placed in-service in 1971. This station has proved to be very difficult to operate because neutron absorption by the ordinary water coolant tends to create unstable behaviour characterized by a strong positive local coolant density effect on reactivity (i.e. void coefficient). Complex detection and control systems must be used to dampen power increases. This effect becomes worse as the reactor size is increased. It is unlikely that larger reactors of the Gentilly-1 type will be built.

The problem of positive void coefficient can be overcome by decreasing the lattice pitch, that is the distance between fuel channels. This leads to the necessity for using fuel enriched with uranium 235 or plutonium. The enriched uranium option is furthest developed in Great Britain where a prototype, designated Winfrith-SGHWR (19), has been in operation for several years. Detailed design of 600 MWe commercial stations is now being carried out in the U.K. The plutonium-fuel option is being pursued in Japan where the FUGEN prototype is scheduled for operation in 1977. Design studies have been carried out by AECL, leading to the design designated as CANDU-BLW(PB). There are no present commitments to build this design.

The primary advantages of enriched fuel in heavy water moderated reactors, compared to the natural uranium fuelled PHW, are increased flexibility in design parameters (such as reduction of the positive void coefficient) and the fact that the requirements for heavy water are substantially reduced. The main disadvantage is the necessity for either purchasing enriched fuel outside Canada or establishing a production capability inside the country. The main advantage of the direct cycle is that it allows better steam conditions within material and economic limits. Its main disadvantage is that the coolant which passes through the reactor also passes through

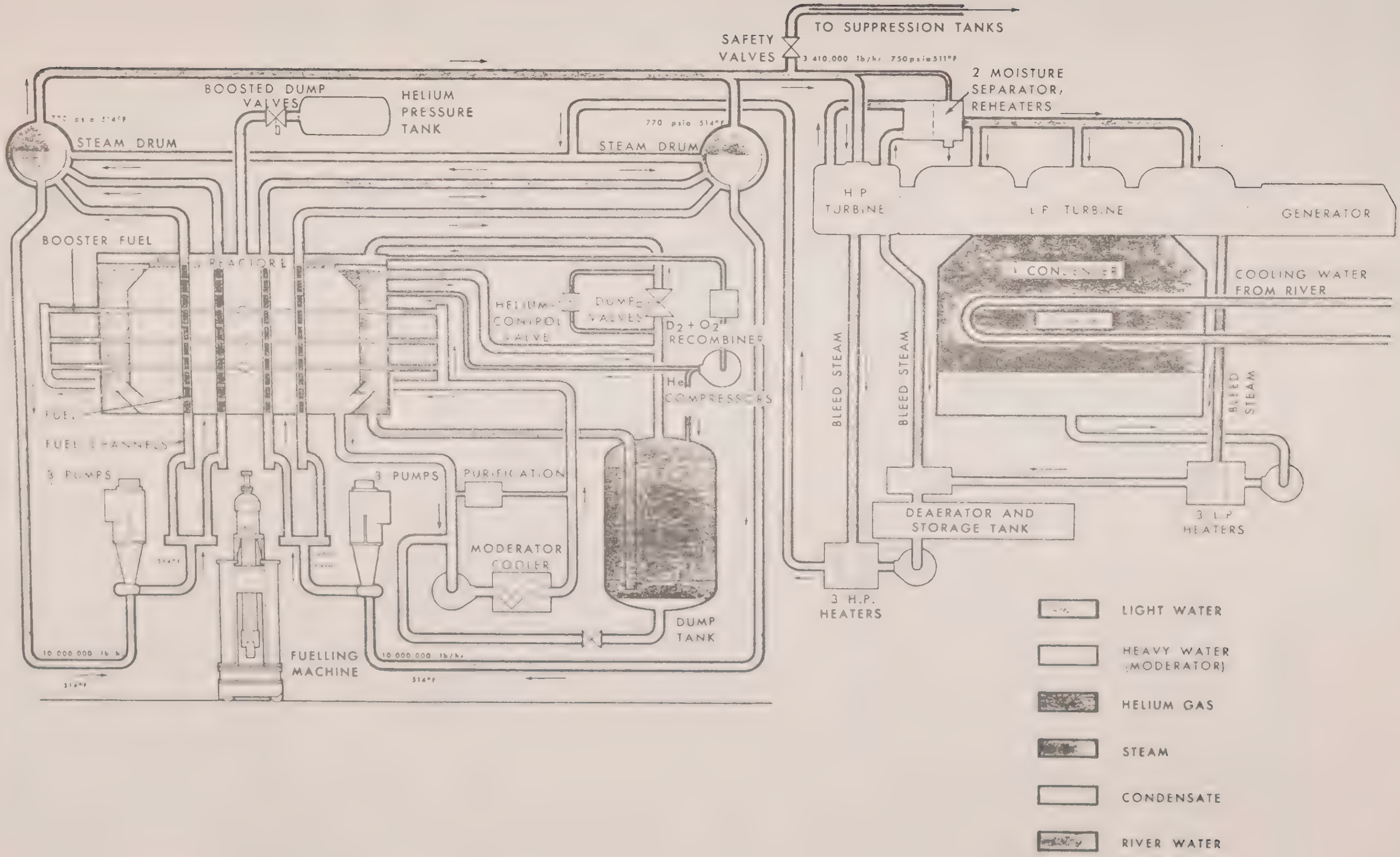

FIGURE 2.1.1–3 SIMPLIFIED STATION FLOW DIAGRAM OF A CANDU (BLW)

the turbine depositing low levels of radioactive materials there.

The second variant of the CANDU design is one with organic fluid as coolant. (Figure 2.1.1-4). This organic cooled reactor is designated CANDU-OCR (20,21). This design avoids the primary circuit pressure limitation of CANDU-PHW by replacing the water with a high boiling point organic fluid. This allows an increased primary circuit fluid temperature and therefore higher steam temperature than CANDU-PHW, while retaining the isolation between reactor and turbine which is provided by the steam generator. This concept has been developed to the stage of a 60 MW (thermal) test facility which was commissioned in 1965, designated WR-1. The federal government decided in 1974 that it did not wish to commit resources to develop both the BLW concept and the OCR concept. AECL chose to continue the BLW development line.

The OCR concept remains as a very interesting development possibility for the future. Aside from potentially low capital cost, it offers the important advantage that the organic coolant becomes only slightly radioactive during operation. Therefore inspection and maintenance of components of the primary coolant circuit can be done with relatively low radiation dose to station staff. There are some potential problems with OCR. For example, the pressure on the turbine side of the steam generator is much higher than that in the primary coolant circuit. If leaks develop in the steam generator tubes the primary coolant could increase in pressure, possibly above the circuit design limit. Also, mixing of water with the organic coolant could pose an operational problem. A second difficulty is that the organic fluid may burn if it is ejected into air from leaks or breaks in the primary coolant loop. Radiolytic and pyrolitic damage of the organic coolant requires substantial make-up requirements and may present a major disposal problem for commercial sized stations. Poorer neutron enconmy in the CANDU-OCR than in the CANDU-PHW results in less energy production per tonne of mined uranium.

These CANDU design variants have in common a number of features which would allow exploitation of the experience and knowhow that has been accumulated during the CANDU-PHW development program. Heavy water technology, fuel designs, pressure-tube

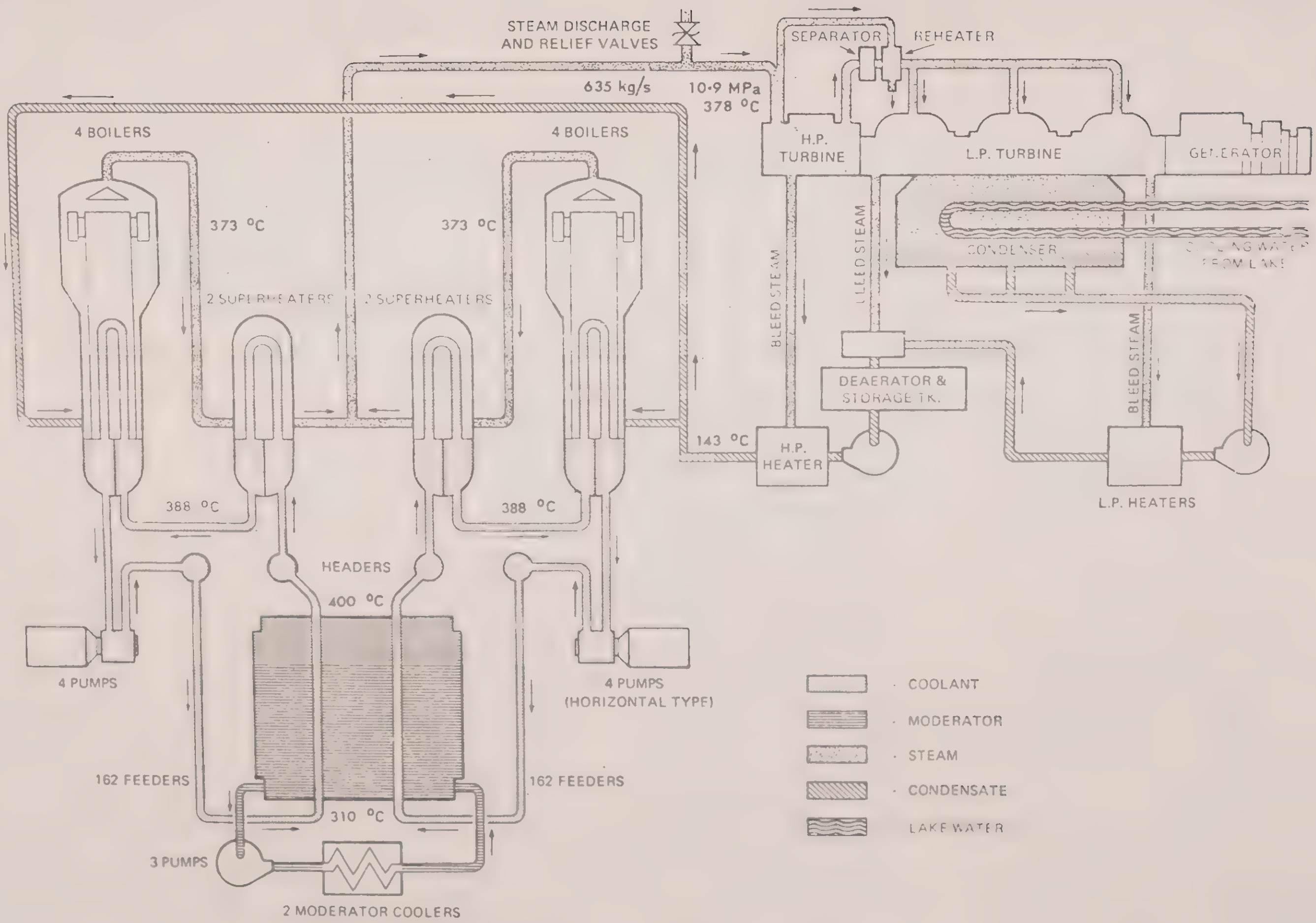

FIGURE 2.1.1–4 STATION FLOW DIAGRAM OF A CANDU (OCR)

technology, etc., are common features of all these concepts. This situation may be contrasted, for example, with the problems which could develop if a fast reactor program were initiated. Designers, technologists, and operating staff would be required to learn new technology, essentially from the ground up. Operating experience from existing CANDU stations could not be applied, and many years would be necessary to obtain in a large staff the same level of competence which now exists in the CANDU-PHW program.

2.1.1.4 Other Reactor Types (22)

The CANDU power system was chosen for development in Canada about twenty-five years ago based on Canadian heavy water reactor experience. Development work was limited to the natural uranium fuelled, pressure tube, heavy water moderated reactor. This program contributed to the success of the effort by limiting variations in the design and held costs to a level which was manageable in Canada. The resulting design is admirably well-suited to Canada's resources and industrial capability.

Some other countries began from different starting conditions and their programs developed in different ways. For example, the United States (U.S.) light water reactor (LWR) was developed first as a prime mover for naval vessels. Uranium enrichment plants were available as a result of their weapons program. At the initiation of the power reactor program the LWR was the only logical candidate because of military experience, industry know-how in design and manufacture and because of the available enrichment. The fast breeder reactor, EBR-1, was first to produce electric power, but the sheer momentum of the LWR program soon left the breeder program behind. Changed economic conditions and renewed resource conservation concerns may lead to redirection of U.S. programs.

Some countries have attempted to carry more than one development program at the same time. The large financial resources of the U.S.A. permitted this course but with limited success in other than the LWR concept. The present U.S. development effort on fission reactors is directed mainly on the fast breeder reactor, to the exclusion of some other promising concepts. Many of the early programs have been cancelled either for lack of funds or because

their initial promise was not fulfilled due to engineering limits on materials, or simply because they were too expensive, rather than because of any conceptual difficulties. This same pattern has emerged in Great Britain, France, and Germany.

The following is a partial listing of reactor concepts which have been brought to commercial application, are under active development, or still show some promise for the future.

(a) Light Water Reactors (LWR) (23,24,25,26)

LWR's can be classified into either Pressurized Water Reactors (PWR) or Boiling Water Reactors (BWR). The common feature of these reactors is that they use ordinary or "light" water as both reactor coolant and moderator, and enriched fuel. Some other features of these reactor types are discussed below.

Pressurized Water Reactor (PWR)

The PWR was developed initially from the system used to power the U.S. nuclear submarines. The name derives from the fact that the reactor coolant system is highly pressurized (to approximately 15-16 MPa) in order to achieve high coolant outlet temperatures without boiling. (See Figure 2.1.1-5). A massive steel pressure vessel with a removable lid is used to contain the relatively compact reactor core. Compactness is achieved by the use of enriched uranium as fuel, with U-235 enrichment levels ranging between 2 and 3.5 per cent. The fuel is in the form of sintered oxide pellets which are stacked into 3.7 m long Zircaloy tubes, called fuel elements. About 200 of these fuel elements are mounted on a square lattice to form a fuel assembly. A large, 1300 MWe PWR, would typically contain about 200 of these fuel assemblies, constituting a total fuel load of approximately 100 tonnes of UO^2. Control of a PWR is achieved either by the use of neutron absorbing control rods which can be inserted into the fuel assemblies, or by varying the concentration of a boron solution in the water coolant. Because of the use of enriched uranium, on-power fuelling is not required. Instead, fuelling operations are carried out every 12 or 18 months, at which time the reactor must be shut down and the lid removed from the pressure vessel. During refuelling usually up to a third of the reactor core is replaced with fresh fuel assemblies. The use of enriched uranium fuel is expected to eventually result in average discharge

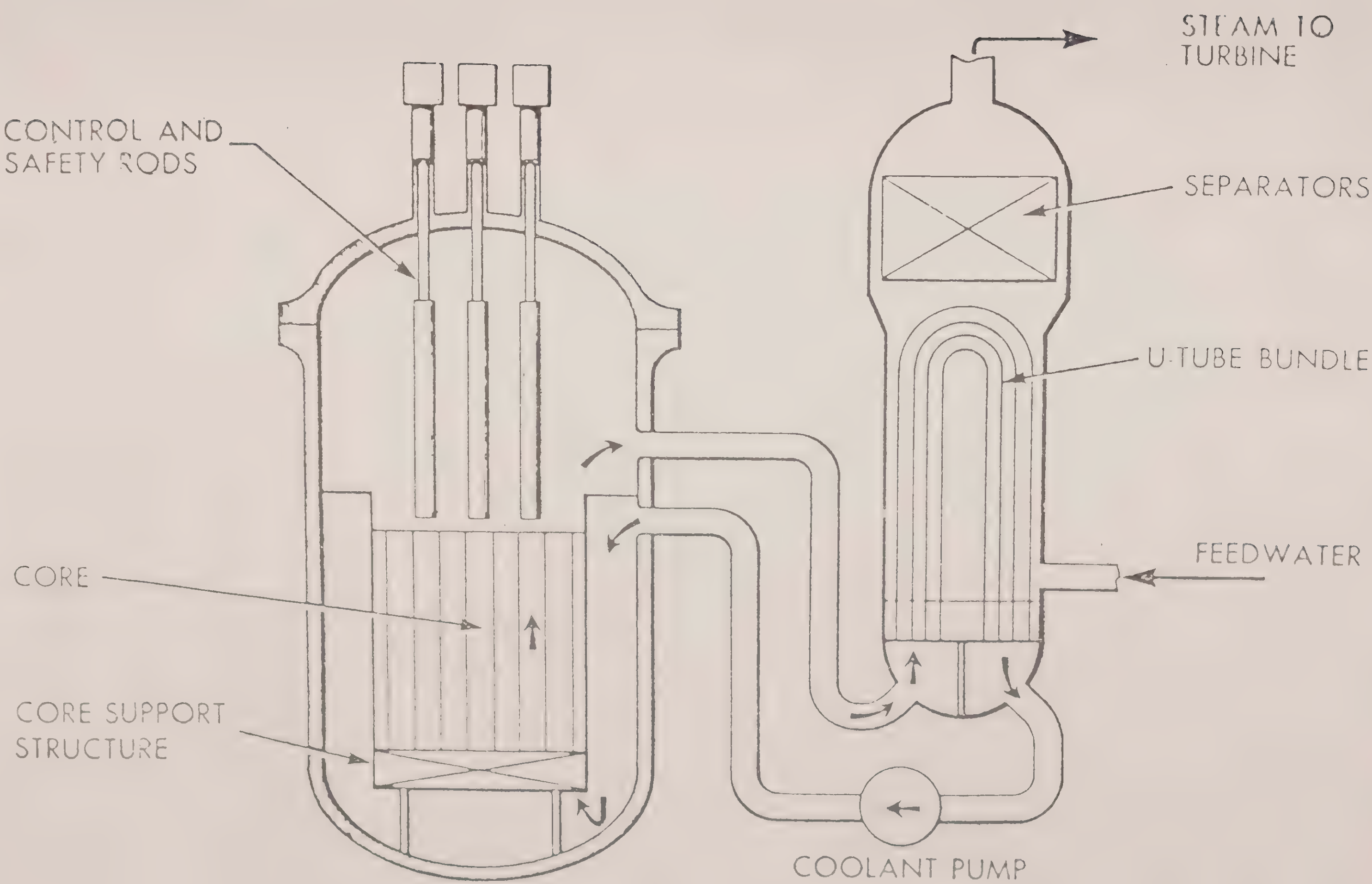

FIGURE 2.1.1–5 SCHEMATIC ARRANGEMENT PWR

burnups of about 30,000 MWD/TeU. Thermal efficiencies in PWR's are of the order of 33%.

Boiling Water Reactor (BWR)

The BWR is the second variant of the light-water reactor family. (See Figure 2.1.1-6). The basis of the BWR depends on the fact that controlled boiling of the water coolant can be achieved in a self-stabilizing condition at only half the equivalent system pressure of a PWR, i.e., at around 7 MPa. The steam generated in the core can be used to drive the turbine directly. In effect, the reactor acts as a recirculation boiler with steam separators and dryers situated in the top section of the reactor pressure vessel. Recirculation of the water from the steam separators and feedwater returning from the turbine condenser is usually achieved with jet pumps located around the reactor core and driven by small external pumps. Minor variations of this design have been introduced in Germany and Sweden.

The BWR uses enriched uranium fuel and Zircaloy cladding with square lattice fuel element assemblies similar to those of the PWR. Control of the reactor is achieved with cruciform neutron absorbing rods which are inserted hydraulically between the fuel assemblies from below the core, and by variation of the recirculation flow rate. Fuelling of the reactor is on an off-load basis at intervals of 12 to 18 months, requiring removal of the pressure vessel lid and steam dryers. The core of a BWR is not as compact as that of a PWR, and together with the jet pumps and steam drying arrangements, this calls for a larger pressure vessel. However, this is offset by the lower operating pressure which allows a thinner walled pressure vessel.

Typical fuel load requirements for a large, 1300 MWe, BWR are about 150 tonnes of UO^2 at an average enrichment level of 2.7%, which is eventually expected to result in an average discharge burnup of 27,500 MWD/TeU. Thermal efficiencies in BWR's are similar to those in PWR's, being of the order of 33 to 34%.

Operating Experience With Light Water Reactors (10,27)

In December, 1957, Shippingport, a 68 MWe PWR plant, became the first U.S. nuclear power plant to begin commercial operation. A few years later, in 1960,

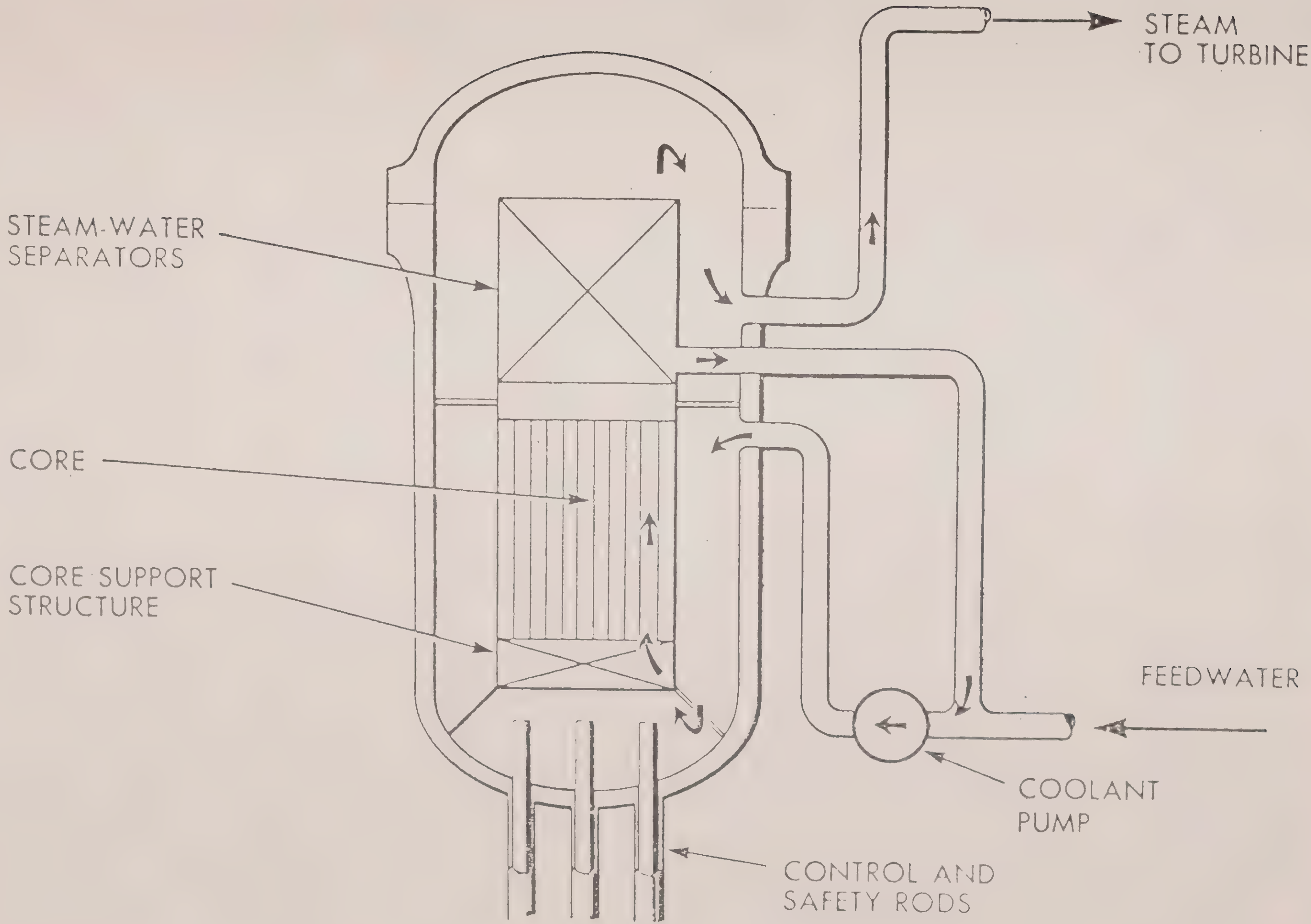

FIGURE 2.1.1–6 SCHEMATIC ARRANGEMENT BWR

the first commercial BWR, the 200 MWe Dresden-1 plant, started producing electrical power. Since those early days LWR development has evolved to the point that today Light-Water Reactors constitute the most widely used nuclear power system in the world. Furthermore, most countries have opted for PWR's and BWR's as the basis of their future nuclear power programs.

As of the end of 1975 there were approximately 47 PWR's and 40 BWR's in commercial operation in the world, excluding Eastern European countries, which represented a total installed capacity of about 66,000 MWe. Of the total number of LWR's, the U.S. accounted for the largest share, having 30 PWR's and 23 BWR's in operation for a combined installed capacity of some 39,000 MWe. These nuclear plants contributed about 8% of the total electrical energy generated in the U.S. during 1975. As of January 1, 1975, approximately 150 additional LWR's were under construction or had been ordered in the U.S. alone, representing a total capacity of 165,000 MWe. Most of these reactors were scheduled for completion between 1979 and 1985, but the economic difficulties facing U.S. utilities coupled with a reduced energy consumption rate during 1975 resulted in subsequent deferrals or cancellations of many of these plants.

LWR development has gone through evolutionary stages involving design changes leading towards the objectives of design optimization and standardization. Typical LWR units currently are built in the capacity ranges from about 2,400 to 3,800 MWt to yield electrical outputs in the 800 to 1,300 MWe range. The maximum unit capacity of 3,800 MWt represents a temporary limit placed by U.S. regulatory authorities in 1973 to streamline licencing procedures. This limit was generally adopted by other countries. The intention is to raise this limit at some time in the future and the unit size would then be limited mainly by technology and economics.

An indication of LWR station performance is provided by a consideration of station availability and capacity factors. In 1973 the average availability factor of some 30 U.S. nuclear power stations was 71%, while the average station capacity factor was 56%. For the first nine months of 1974 the availability factor rose slightly to 71.6%. More recent statistics are not yet available, but according to Edison Electric Institute studies there

is an upward trend in long-term overall nuclear station availability.

The early LWR stations have experienced some technical problems which resulted in construction and operating delays and which contributed to losses of availability and limitations of capacity factor. Two problems which affected a number of stations were fuel densification and condenser cooling water in-leakage.

Fuel densification is a phenomenon which results in shrinkage of UO^2 fuel pellets along their length and diameter during operation. The possible consequences of these effects are an increase in fuel pellet temperatures at a given power level due to heat transfer degradation, and fuel cladding collapse due to gap formation between fuel pellets and external pressure on the fuel element. These consequences have implications on safety aspects during postulated accident conditions and led to U.S. regulatory authorities imposing limitations on the power ratings of a number of stations, causing a substantial loss of energy production. Other countries in the world with LWR stations placed similar restrictions. Since then, the fuel densification problem has been solved through fuel design improvements and manufacturing changes, and the power rating restrictions have been lifted for those stations in which the earlier fuel was replaced by the improved fuel.

The problem of condenser cooling water in-leakage in which impure water intrudes into the Nuclear Steam Supply System (NSSS) is a different situation. The consequences of condenser leakage differ for BWR's and PWR's. In a BWR, the major problem is that in-leakage is introduced directly into the primary coolant system and can cause chloride stress corrosion cracking of stainless steel components. In the PWR case, salt in condenser cooling water in-leakage, if not adequately controlled, can lead to the deposition of solids which can affect steam generator tubing integrity. Condenser cooling water in-leakage is a problem which is still being investigated, although rapid progress has been achieved in eliminating it through improvements in chemistry control and materials selection.

(b) Gas-Cooled Reactors

Magnox Reactor (28,29)

The Magnox reactor is one of the earliest types of nuclear reactors to be used for large scale commercial electric power production and represents the first development in the generic line of gas-cooled reactors. It was developed mainly in the UK and France where units have been in commercial operation since the early sixties. At present each of these countries has a number of gas-cooled reactor stations in service for a combined total capacity of about 8,000 MWe. The name Magnox is derived from the use of a magnesium alloy as fuel cladding material. The Magnox reactors use natural uranium metal as fuel, while carbon dioxide at relatively low pressure and temperature is used as coolant. The fuel elements are stacked in channels in a massive graphite pile, which acts as the moderator material. The choice of materials limits the plant performance to a large extent.

The early Magnox reactors employed large spherical steel pressure vessels connected by ducts to the steam generator units and gas circulators, but in later designs prestressed concrete pressure vessels were used with an integral arrangement of steam generators. The use of natural uranium requires continuous fuel changing operations similar to the CANDU-PHW reactors and therefore the Magnox reactors also employ an on-power fuel handling system.

The British and French experience in operating Magnox reactors has not been without its share of problems. In particular, CO^2 oxidation of certain types of steel has led to forced derating of the plants and gas flow induced vibrations have resulted in fatigue failure of components. Largely because of their experience with Magnox reactors, the French decided in late 1973/early 1974 to abandon further development of gas-cooled reactors and to concentrate their efforts on light water reactors. It is interesting to note, however, that the British Magnox reactors now produce power more cheaply, even though they are derated, than equivalent fossil-fuelled stations. This is due to the dramatic price increases for coal and oil rather than the inherent economics of this system.

Advanced Gas-Cooled Reactor (AGR)

The AGR is a development of the Magnox reactor designed to raise gas coolant temperatures and thereby improve steam conditions. (See Figure 2.1.1-7). In the AGR the fuel cladding material was changed to stainless steel, which necessitated a change to enriched uranium (to between 2% and 3% in U-235) as fuel. The latter is in the form of sintered oxide pellets which are packed into stainless steel tubes and combined into 36-element fuel assemblies which are located within channels in the graphite moderator. On-power fuelling is required to obtain a high plant availability. The reactor core and an array of steam generators which are arranged circumferentially around the core, are contained in a prestressed concrete pressure vessel. Due to the inherent safety of the concrete pressure vessel, the high thermal capacity of the graphite and the ceramic fuel, no special containment building is required to deal with the possible effects of a primary circuit rupture.

The UK initiated its AGR program during the Magnox phase of reactor construction and operation and committed itself to constructing several AGR's. However, the AGR program has been plagued by numerous problems causing delays of 3 to 4 years in the in-service dates. The first AGR's are only now going on-line and the last one is scheduled to be completed by 1978.

High Temperature Gas-Cooled Reactor (HTGR) (30,31,32,33,34)

The HTGR represents the latest evolution of the gas-cooled reactor concept to yet higher coolant temperatures and still better steam conditions. (See Figure 2.1.1-8). This is achieved by using helium as the coolant, and fuel with a ceramic coating instead of metal cladding. The HTGR development effort has been concentrated in the United States where two prototype plants are in operation, and the first commercial stations were ordered for operation around 1980. A variant of the HTGR, known as the Thorium High Temperature Reactor (THTR), has been developed separately in W. Germany using a novel pebble bed core concept. A 300 MWe prototype plant is currently under construction.

The HTGR fuel consists of enriched uranium in the form of small uranium carbide spheres. These are

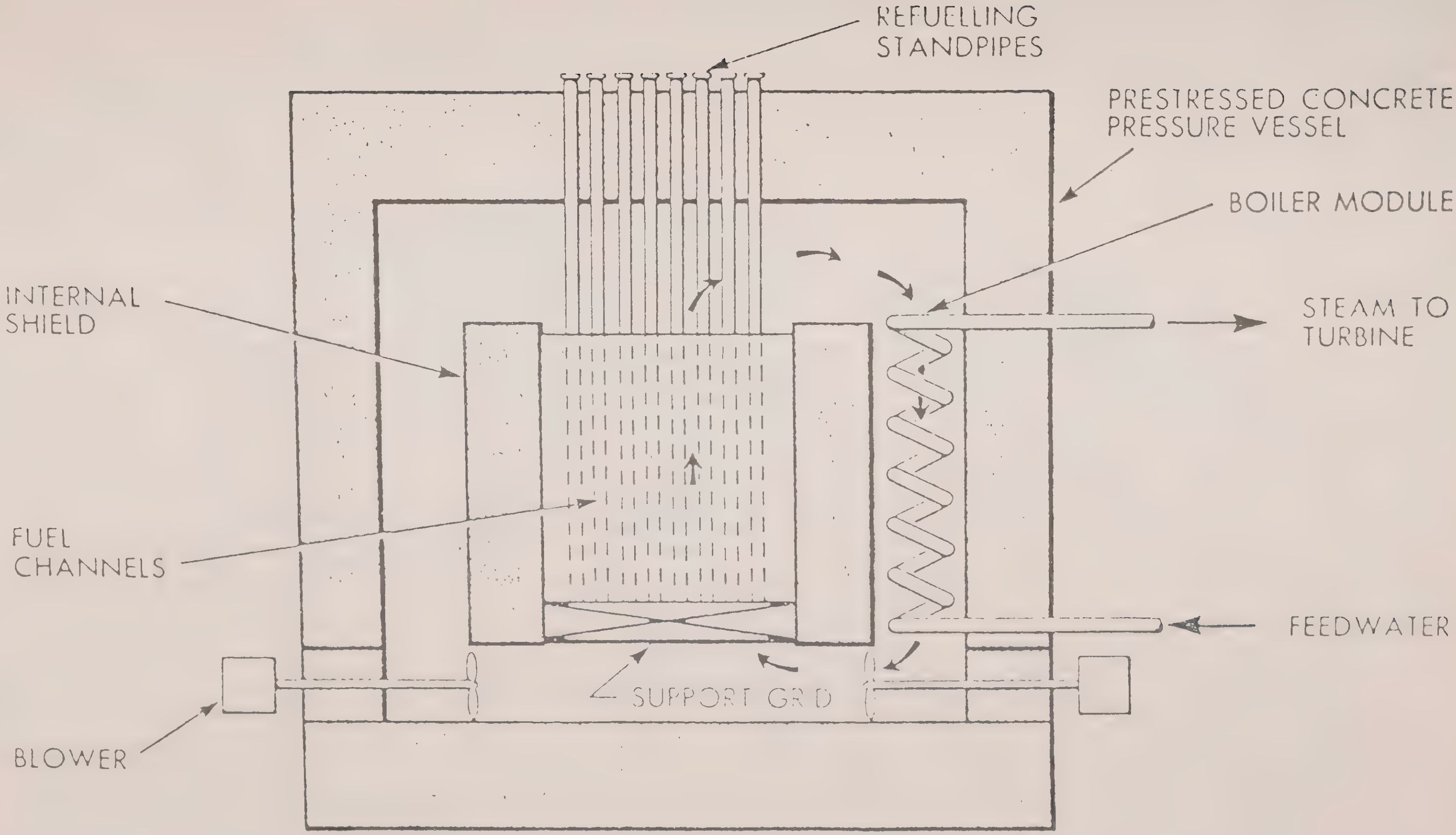

FIGURE 2.1.1–7 SCHEMATIC ARRANGEMENT AGR

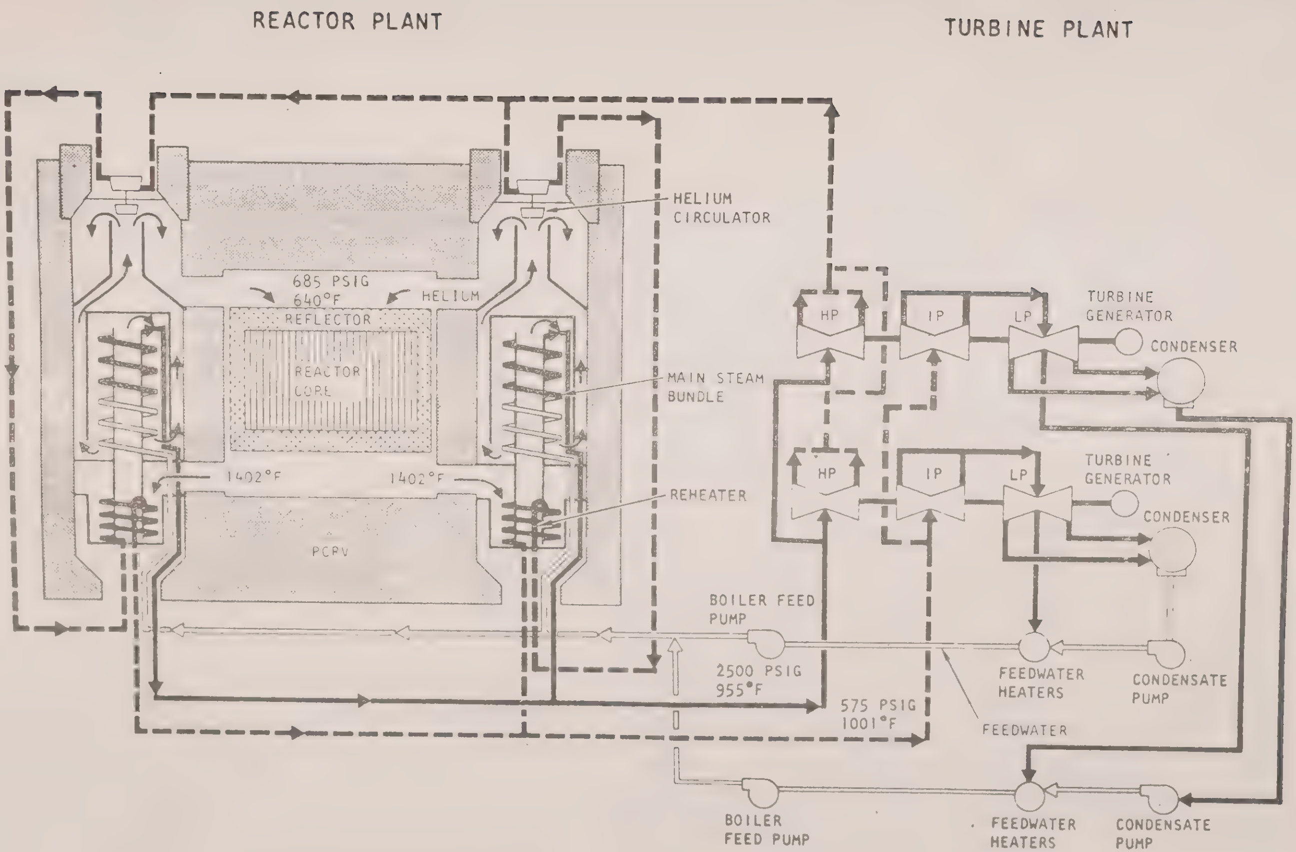

FIGURE 2.1.1–8 SCHEMATIC ARRANGEMENT HTGR

coated with layers of graphite and silicon carbide to form coated particles which need no further cladding to retain radioactive fission products. The coated enriched uranium particles are mixed with similarly coated thorium carbide particles. These are packed together into axial cavities in hexagonal graphite blocks which serve as combined fuel assemblies and moderator blocks. Axial passages through these fuel-moderator blocks allow coolant passage through the core. The reactor core and the steam generators are all contained within a concrete pressure vessel.

The HTGR is characterized by high thermal efficiencies of about 40% and high fuel burnups of about 100,000 MWD/TeU. During operation the thorium and U-238 are converted to U-233 and plutonium, respectively, both of which are recoverable from the spent fuel as reusable nuclear fuel. The HTGR development received a severe setback furing 1974-75 when utilities cancelled or withdrew orders for HTGR's and in the latter part of 1975 with the announcement from Gulf-General Atomic, the prime vendor, to withdraw from further commercial development of this reactor concept. This move has resulted in considerable uncertainty concerning the future status of the HTGR.

Remaining development work on HTGR is mostly in the area of fuel reprocessing. The future of this work, carried on mostly at Oak Ridge National Laboratory, is uncertain.

(c) Breeder Reactors (35,36,37,38)

The term breeder reactor refers to a concept in which more fissile fuel (uranium-233 or plutonium) is produced than is consumed in the reactor. The advantage of this process is that essentially all of the mined fuel can be burned, and the excess of fissile material over that required to keep an existing reactor running can be used to fuel new reactors. Existing resources of uranium are sufficient to supply breeder reactors for hundreds of years. Existing stocks of tailings from enrichment plants could provide a good fertile fuel source for many years.

There are two classes of breeder reactors, the so-called "thermal" breeder and the "fast" breeder. The thermal breeder is similar in most respects to the familiar CANDU system, i.e. most fissions are caused

by low-energy neutrons. The design details are necessarily different so that breeding can be achieved, however the basic physics of the processes make this a very difficult goal to reach. The two types of thermal breeders in existence are the light-water breeder (LWBR) and the molten salt breeder (MSBR). The first has reached the prototype stage under sponsorship by the U.S. Navy. Very few details are available, but is is unlikely that this system will be competitive in the commercial market. The MSBR has not been tested to the prototype level and development has been stopped for lack of funds. The concept can use thorium as fuel and has many attractive features such as very low fuel inventory and simplicity of mechanical design. Because of international concentration on fast breeder development it appears likely that this concept will remain on the drawing board.

The fast breeder reactor is basically different in that most fission occurs at high neutron energy. This is achieved by using a high concentration of enriched fuel and a minimum of moderating materials in the reactor. Typically, stainless steel is used for fuel sheath and structural members, and either sodium or helium as the coolant. Most intensive work is concentrated on the sodium-cooled option.

The sodium-cooled fast breeder (LMFBR) is characterized by its very small size relative to thermal reactors (and resultant high power density), by coolant at very low pressure, and by high operating temperature. (See Figure 2.1.1-9). Sodium undergoes a violent chemical reaction with water, so that the reactor coolant must be isolated from the steam generator by an intermediate heat transport loop. The high operating temperature leads to high efficiency of the steam turbine (about equivalent to that of modern fossil-fuelled plants) but the complexity of sodium systems results in relatively high capital cost. Capital costs are quite uncertain because of the early development status of the concept. The fuel is very expensive, but since it achieves a high burnup in the reactor fuel cycle costs are expected to be low. There is, however, considerable uncertainty in the fuel cycle cost projections which depend primarily on the cost of fuel reprocessing and fabrication both of which are at an early stage of development.

The helium-cooled fast breeder (GCFR) (30) is characterized by a lower power density than the

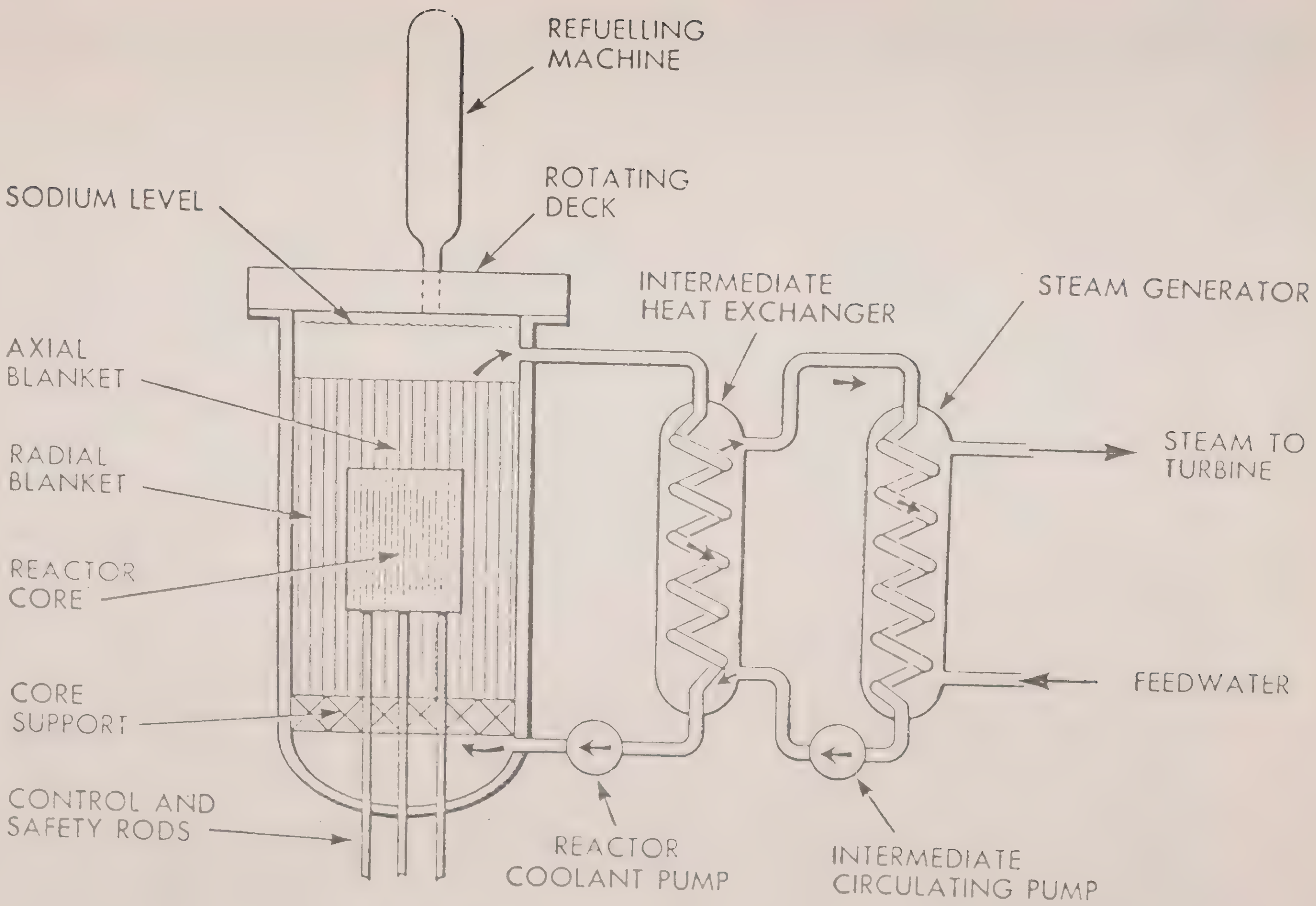

FIGURE 2.1.1–9 SCHEMATIC ARRANGEMENT LMFBR

LMFBR, a very high pressure coolant contained in a prestressed concrete vessel, and better breeding performance than the LMFBR. It is possible to use a direct gas-turbine cycle for very high efficiency and low heat rejection requirements, but gas turbine technology for high pressure application is not yet fully developed. The major disadvantage of the GCFR relative to the LMFBR is the lack of an emergency heat sink following leakage or break in the coolant circuit. Sodium has a very high heat capacity and is under low pressure so that it can absorb large amounts of decay heat after shutdown. By contrast, the helium gas has a low heat capacity and is quickly lost from the pressure vessel in the event of a leak or break. Only conceptual design and some research and development work have been done on this concept. No commitments have been made for prototype plants.

Status of Development

Development of fast breeder reactors dates back to 1946 when an experimental facility was operated at Los Alamos National Laboratory. Several experimental reactors of the LMFBR type have been built and operated since, and more recently full-scale prototypes have been operated in Europe, and planned in the USA. Development work is essentially complete except for steam generators, which continue to cause problems. A major development necessary prior to large-scale use of breeders is the establishment of fuel reprocessing and fabrication plants.

France

The French breeder reactor program began with the construction of a small prototype named RAPSODIE. This reactor was operated initially at 20 MWt and later at 40 MWt and is currently used as an irradiation facility. In 1965 preliminary studies of a full scale prototype, PHENIX, started and by the end of 1973 this 250 MWe reactor reached full power. The startup period was marked by a number of minor incidents, however their effect on the planned program was quite negligible. Since the beginning of commercial operation (July 1974) the availability factor has exceeded 70% and the maximum burnup target of 50,000 MWd/TeU has been reached.

Design of a 1,200 MWe reactor, SUPERPHENIX, is now in an advanced stage and commercial operation of this reactor by a French-Italian-German consortium is forecast for 1980.

Electricite de France is now giving consideration to a commercial station with twin units of 1,200 to 1,800 MWe which would be ordered in 1978 or 1979 for operation in the mid 1980's.

USSR

A 350 MWe reactor has been in operation since 1972 and a 600 MWe unit is at an advanced stage of construction with criticality scheduled for 1977. The USSR fast breeder reactor program calls for one year of operating experience from the 600 MWe station before starting construction of a 1,500 MWe station. This should result in the breeder being an alternative to the thermal reactor by the end of 1980's.

UK

The first criticality of the prototype Fast Breeder, a 250 MWe reactor, took place in March 1974. The initial period of operation has suffered a series of problems mainly on the conventional side of the plant. At the end of 1975 the output was still limited to 30 MWe, however full power operation is believed to be attainable shortly.

Consideration is now being given to a commercial plant in the 1,200 MWe range, however no definite decision has been reached.

USA

Several experimental reactors of this type have been operated in the U.S.A. since the 1950s. The best known of these experimental facilities is the FERMI-1 plant near Detroit. This plant experienced many difficulties in operation over a period of years, primarily with sodium pumps and heat exchangers. A partial flow blockage led to melting of a small amount of fuel and forced a two-year shutdown for repair (no release of radioactive materials and no injury or death resulted from this incident). The station was restarted after repair but has now been decommissioned due to a lack of financial support. The major operating fast reactor test facility in the U.S. is EBR-II, which has been run very successfully as a fuel test reactor for over ten years. A large test reactor, FFTF (Fast Flux Test Facility) is scheduled for startup in 1978. Large development programs have been underway in the U.S. since the 1950's, but they have not advanced as rapidly as

programs in other countries. Development initiative has largely been taken over by the European countries listed above. General design of a demonstration plant, the Clinch River 380 MW(e) reactor, is nearly finished. The project schedule calls for first criticality in 1982 followed by five years of demonstration. Commercial introduction of this type of reactor in the U.S.A. may be realized by 1990-1995.

Fast Breeder and CANDU

All major fast breeder reactor (FBR) programs are committed to plutonium as fuel, basically because of the higher margin for breeding than for any other fissile isotope. The initiation of a commercial FBR program will be greatly facilitated by the large inventory of plutonium generated by thermal reactors. It is credible that, in the future, the best balance of economy would be achieved by a system strategy based on a mix of thermal and fast reactors.

The CANDU system would be a good choice for the thermal reactor in a mix of thermal and fast reactors. Compared to other commercial thermal reactor systems, the CANDU-PHW makes more efficient use of the U-235 available from nature and also generates more plutonium per unit of uranium mined. The plutonium could be a valuable fuel source for introduction of fast reactors.

2.1.1.5 Alternative CANDU Fuel Cycles

The term fuel cycle applies to the sequence of operations from mine to reactor to spent fuel storage and either disposal or reprocessing, fabrication and re-insertion of all or part of the fuel materials back into the reactor. The CANDU power system can be operated with a number of different fuel cycles, depending on the economic situation. (See Figure 2.1.1-10). These cycles and their application to the basic CANDU-PHW and its variants are outlined in the following discussion.

(a) Natural Uranium Fuel Cycle

This cycle is presently employed in all CANDU-PHW power reactors. The mine output is called yellowcake, consisting largely of U^3O^8. The yellowcake is refined and reduced to uranium dioxide, formed into pellets and placed into zirconium fuel

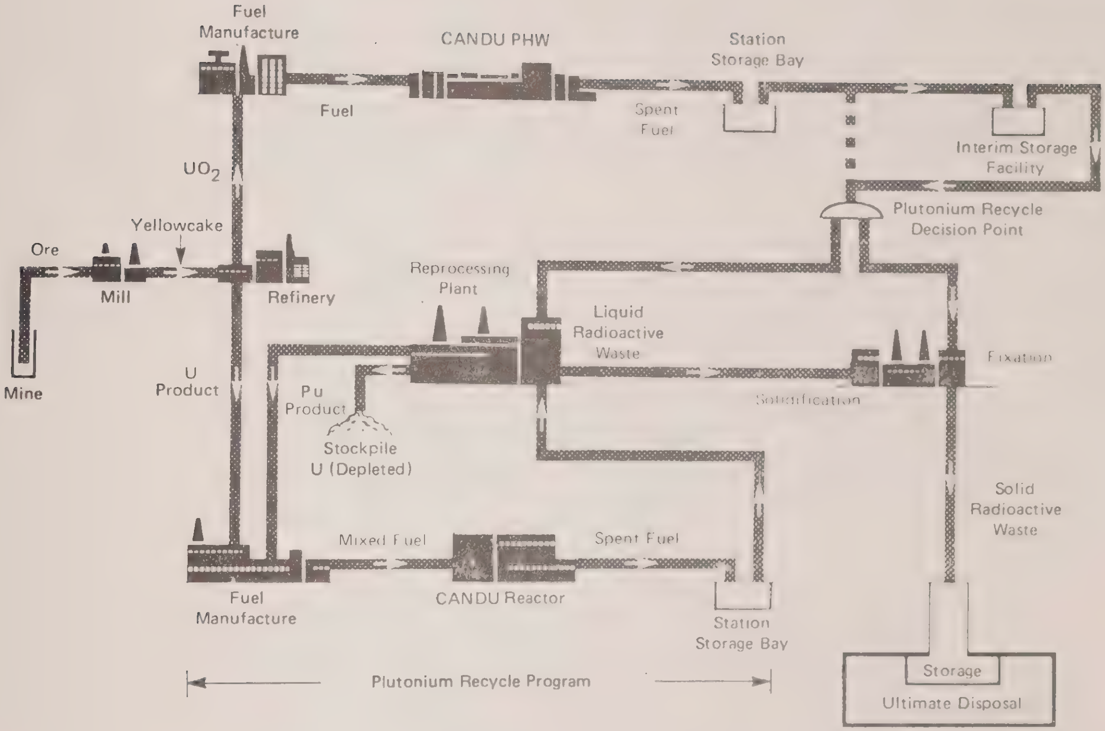

FIGURE 2.1.1–10 POSSIBLE CANDU FUEL CYCLE

sheaths to form a fuel element about 50 cm long. The elements are formed into fuel bundles containing typically 28 or 37 elements. These bundles are loaded into the reactor. The uranium is referred to as 'natural' because it contains only the naturally-occurring isotopic composition of 0.7 per cent uranium-235 and 99.3 per cent uranium-238. The uranium-235 is fissile, that is, capable of fissioning after absorption of one thermal neutron. The uranium-238 is fertile, that is, capable of being converted to a fissile isotope by the absorption of one neutron.

Because of the small percentage of natural uranium which is fissile, it is important in this cycle to use structural and moderating materials which capture very few neutrons, so that the chain reaction can be maintained. The CANDU system employs zirconium alloys and heavy water for these functions. The major characteristics and design features of CANDU follow from this deliberate choice of natural uranium, in contrast to other concepts which require fuel to be enriched, that is, to contain a higher percentage of fissile isotopes.

The fuel has an average dwell time in the reactor of about 1-1/2 years and at discharge has achieved a burnup of approximately 7,500 MWd/TeU. During irradiation a small portion of the uranium-238 undergoes neutron capture to form plutonium-239, a fissile isotope of plutonium. Some of the generated plutonium fissions, some undergoes further neutron capture to form higher plutonium isotopes, and some remains in the fuel. The discharged, or spent, fuel thus contains about 0.3 per cent of uranium-235 and 0.26 per cent of fissile plutonium, with the amount of uranium-238 being substantially unchanged at 98.5 per cent. About 1.25 fissions take place in the CANDU-PHW fuel per initial uranium-235 atom. The isotopes which are produced during fission, called fission products, also capture neutrons. This, and the fact that the fissile content of the fuel slowly decreases during irradiation, is the reason that the fuel must be discharged and fresh fuel added to maintain the chain reaction.

The rate of decrease of fissile atom concentration with irradiation is a measure of the conversion ratio, that is the relative rate of production of fissile atoms versus their destruction by fission or further neutron capture. The CANDU-PHW with natural uranium fuel has a conversion ratio less than unity.

Other fuel cycles and reactor concepts can be devised in which the conversion ratio is greater than unity. These systems are called breeders because they produce more fissile atoms than they consume during irradiation.

The natural uranium fuel cycle presently employed is a once-through cycle. That is, the fuel passes through the reactor once and the spent fuel is stored. There is no reprocessing of the spent fuel and no refabrication of new fuel using fuel components which have already been in the reactor.

The CANDU-PHW system has good uranium utilization, the electrical energy generated per tonne of mined uranium being higher than that for any other system presently in commercial operation. Ontario is also relatively well endowed with uranium resources. These two facts are encouraging, at least in the near term, from a resource availability point of view. From the point of view of desirable simplicity in the fuel cycle, the natural-uranium cycle is best because it avoids the need for complex industries for enrichment, reprocessing, and enriched-fuel fabrication. Two major factors may combine to change this situation in the long term.

First, the available supplies of uranium ore may be depleted by strong world demand (39). There is a large uncertainty in the quantity of uranium which can be recovered economically. Also the recent dramatic rise in the world uranium price has resulted in Canadian buyers competing for Ontario uranium with several foreign buyers at world prices. Fortunately the very small contribution of uranium cost to the overall cost of power produced from CANDU-PHW reactors confers two important advantages. First, uranium price increase has less impact on the cost of electricity for Ontario power users than for those with other nuclear systems, and second, the scope for recovery of low concentration uranium ores is expanded. The CANDU-PHW power cost is less sensitive to uranium ore cost than all other concepts except the fast breeder reactor.

The second factor which could change the highly favourable position of the CANDU-PHW reactor fuelled with natural uranium is its relatively high capital cost. There is a trend toward the situation in which the rate of installation of new generation facilities is controlled by the supply of capital rather than by the expected demand for electric power. This effect

produces motivation for capital cost reduction. Some of the alternate fuel cycles offer the opportunity for design modifications to achieve this goal.

In view of large future uncertainties outlined above, and the long time necessary for introduction of alternate fuel cycles and reactor concepts, prudence dictates close examination of these options and identification of the steps necessary for implementation. Atomic Energy of Canada Ltd. has recently proposed a long-term development program aimed at establishing the technology of reprocessing and fabrication of mixed oxide fuels for possible application in the future.

(b) Enriched Uranium Fuel Cycle (40)

Enriched uranium refers to uranium which contains a higher than naturally-occurring isotopic content of uranium-235. The uranium isotopes are, of course, chemically indistinguishable in their normal state and separation processes must rely on the small differences in physical properties which result from their slightly different masses.

The only commercially available enrichment plants utilize a gaseous diffusion process, in which the different rates of diffusion through a membrane of the isotopes uranium-238 and uranium-235 are used to concentrate uranium-235 in one process stream. Because the rates are very close to being the same it is necessary to use hundreds of diffusion stages to achieve desirable concentrations. The process requires the use of power consuming gas compressors, so that the whole plant demands a large supply of electrical power. Most enrichment capacity is now located in the USA, though the USSR is likely to become an important supplier in the future. The U.S. government has been reluctant to commit capital to build new enrichment facilities, and the return-on-capital and tax positions for private financing have resulted in little interest from the private sector. As a result there is an impending world shortage of enrichment facilities in the 1980's. Escalating energy costs due to large increases in fossil fuel prices have resulted in large price increases for enrichment services. The current situation is quite unstable.

A centrifuge enrichment process is receiving wide attention in the U.S.A. and Europe. Its prime advantage is that it can be built in small-capacity

blocks, in contrast to the diffusion process which requires commitment of very large capacity, and therefore capital, at one time. It appears to be competitive with the diffusion process although its actual cost is somewhat speculative at the present time.

Two other processes are at the research and development stage. The nozzle process employs separation produced by abrupt changes in direction of gas streams, and the laser process raises the uranium-235 to an excited state by selecting a laser frequency near to one of the electron excitation levels. In the excited state the isotope is much more reactive chemically, so that separation is possible. Neither the nozzle nor laser separation method appears to be close to commercial application.

The use of slightly enriched uranium in the CANDU-PHW appears to be technically feasible but financially unattractive. The rapidly rising uranium enrichment costs and insecure supply situation are confirming the latter conclusion. In addition, enrichment would tend to reduce the good resource utilization of the CANDU-PHW. The most likely use of enriched uranium at the present time is not as an end fuel cycle, but as a means of accomplishing the transition to a different long-term cycle. For example, it may be feasible to initiate a thorium fuel cycle prior to the availability of plutonium recovered from spent CANDU-PHW fuel. The first reactor fuel charge of a thorium-fuelled reactor could consist of thorium plus small quantities of highly enriched uranium. The use of enriched uranium would be largely phased out as uranium-233 from the reprocessed spent thorium fuel became available.

Another possible use of enriched uranium is to start the variant of the CANDU system identified as the boiling light water plutonium burner, CANDU-BLW(PB). Rather than being forced to commit a plutonium reprocessing plant, a fuel fabrication plant and a reactor to use their product more or less simultaneously, the projects could be "decoupled" by using enriched uranium in the early life of the BLW(PB) system.

(c) Plutonium Recycle (41,42)

Plutonium recycle is achieved by reprocessing the spent fuel from a reactor to extract the plutonium. The plutonium is then mixed with uranium and the

mixed oxide is used for the fabrication of new fuel. The new fuel can be used as a feed to either the same reactor in which it was generated, or to a reactor specifically designed for the utilization of such fuel.

Plutonium, being a different element from uranium, can be separated from the other products in the spent fuel by a chemical separation technique. This process has been performed on an industrial scale for weapons and research purposes. Commercial reactor application is not well established. There are also certain problems in the refabrication process mainly associated with ensuring that accidental criticality does not occur and that the highly toxic plutonium is contained.

The application of plutonium recycle to the CANDU-PHW has however received considerable study and is, in principle, quite feasible. The incentive for doing so is well established from a resource utilization point of view. The plutonium concentration of the refabricated fuel would likely be of the order of 0.3% fissile plutonium. This level of plutonium would provide sufficient additional reactivity to approximately double the burnup of natural uranium fuel.

Under present economic conditions the additional burnup is not sufficient to compensate for the reprocessing cost and the added fabrication cost. However, as uranium costs rise the increased burnup becomes increasingly valuable, and within a decade or so, plutonium recycle in CANDU-PHW's may be a sound financial proposition.

A promising application of plutonium recycle is with the CANDU-BLW(PB). This system offers decreased heavy water requirements and somewhat lower capital cost relative to the PHW as its main development incentive. This concept cannot utilize natural uranium fuel. Its conversion ratio is less than unity, so that fissile material must be added to maintain the system. It appears that one reactor burning natural uranium on a once-through cycle could supply enough plutonium to make up the fissile isotope deficiency in about four BLW(PB) reactors of the same output.

Fuel reprocessing and fabrication plants are in early development stages in various countries of the world.

Work is required in both these areas to develop systems specifically for CANDU reactors.

(d) Thorium Fuel Cycle (43,44,45)

The naturally occurring isotope of thorium, thorium-232, is fertile. On neutron capture it forms thorium-233 which subsequently decays to uranium-233, which is a fissile fuel. Thorium is not presently used in any commercial reactor system. However its abundance in Ontario is estimated to be at least as great as that of uranium, and possibly several times greater. In the world it is believed to be more abundant than uranium by a factor of about four. There is therefore considerable incentive to tap this potential resource. Some preliminary investigations have been made as to the possibility of a thorium cycle being utilized in a CANDU type reactor. While a great deal more work is required, the use of thorium appears to be feasible.

The thorium cycle would be started by fuelling a reactor with thorium enriched with a fissile isotope, either plutonium or uranium-235. On discharge from the reactor the original fissile isotope would be depleted but uranium-233 would have been generated by the neutron capture process described above. This uranium would be chemically separated from the thorium and used for the fabrication of a new thorium-uranium-233 fuel. The discharged fuel from this and subsequent cycles would again be reprocessed to extract more uranium-233.

The amount of uranium-233 extracted from the spent fuel may not be a sufficient source of fissile atoms for the next re-load. However, any shortfall could be made up of fissile plutonium extracted from the spent fuel of the CANDU (PHW) reactors. The possibility of adjusting the thorium cycle to actually create more uranium-233 than is burnt also exists. Such a thorium reactor would, in fact, be a breeder reactor and the excess uranium-233 would be used to startup new thorium reactors. Design modifications necessary to achieve breeding may adversely effect economics, so that it is not clear that this course of action is the one which would be employed.

If thorium proves to be relatively plentiful and cheap to extract from the earth each refabrication of fuel could be done with newly mined thorium. This would alleviate the need to extract the fission

products from the spent thorium fuel. In the longer term, however, such separation would probably be performed allowing the thorium to be recycled many times. Clearly a breeder thorium fuel cycle, which re-utilized the thorium, would virtually banish concerns of resource depletion.

Successful major development work is required in three broad areas before the above ideal situation is attainable. From the reactor viewpoint much more knowledge is required on the physics of thorium fuels. The problems of reprocessing are parallel to those encountered in reprocessing uranium-plutonium fuels although the present state of the art is less advanced for thorium fuels. Thorium fuel reprocessing would share many problems with the reprocessing of uranium-plutonium fuels but the higher gamma fields from thorium would add to the radiation shielding concerns already inherent in uranium-plutonium reprocessing.

2.1.1.6 Summary of Reactor Options (46)

Table 2.1.1.6-1 provides a general summary of the advantages and disadvantages of the various systems for Canadian application - with the low numbers indicating most fabourable. Since a degree of subjectivity is involved, the systems cannot be reliably ranked simply by adding all the numbers. The table is intended only as a broad qualitative guide. The remainder of this section provides a brief justification for the ranking indicated.

(a) Security of Fuel Supply

The use of natural uranium obviously justifies the high ranking of the PHW and OCR concepts. Fuel reprocessing is not yet on a firm commercial basis and is not available at all in Canada. Uranium enrichment, also unavailable in Canada, will be in short supply everywhere in the early 1980's.

(b) Utilization of Fuel

As seen earlier, the breeder has overwhelming advantages compared to all others in this regard. The good neutron economy of the CANDU places it a poor second.

Table 2.1.1.6–1

Comparison of Reactors for Canadian Application

	LWR's PWR–BWR	HTGR	LMFBR	CANDU Adaptations			
				PHW	BLW–PB	OCR	Valubreeder
SECURITY OF FUEL SUPPLY	7	5	3	1	3	1	5
– Raw material							
– Enrichment							
– Reprocessing							
UTILIZATION OF FUEL %	7	4	1	2	5	5	3
UTILIZATION OF EXPERIENCE	2	6	6	1	3	4	5
Design innovations							
Material applications							
Manufacturing							
– Operating							
VERSATILITY OF CONCEPT	2	7	6	1	3	4	5
Different fuels							
Load following							
Increased output							
PERFORMANCE	2		–	1	–	–	–
– Reliability							
– Annual Capacity Factor							
– Cycle efficiency	(31%)	(39%)	(39%)	(30%)	(31%)	35%	35%
MAINTAINABILITY	6	1	7	4	4	1	1
– Access							
– Inspectability							
ENVIRONMENT ASPECTS							
– Reject heat	5	1	1	7	5	3	3
– Radioactive wastes	3	3	3	1	3	2	3
– during operation							
– during fuel reprocessing							
– final disposal							
SAFETY AND LICENCING	5	6	7	1	2	3	3
COSTS							
– Capital plant	1	6	7	5	2	3	3
Capital for fuel cycle	7	6	7	1	3	2	4
Capital for D_2O supply	1	1	1	7	4	5	6
– Fuelling cost			2	1			
– Energy Cost (@ U_3O_8 less than $50/lb 1974 dollars)	7	6	5	1–4	2	3	1

(c) Utilization of Experience

The Canadian national program has been built around the CANDU-PHW. The great success of the Pickering GS 'A' provides a solid foundation for the further development of the CANDU concept in Canada.

(d) Versatility of Concept

The potential for several different fuel cycles justifies a high CANDU-PHW rating.

(e) Performance

Pickering GS 'A' is mainly responsible for this rating. In the U.S.A. and elsewhere, the LWR concept is fully commercialized. The other generic types are in developmental stages.

(f) Maintainability

The inherently lower radiation fields are of most significance to the highly rated concepts. Obvious difficulties of working with liquid sodium mitigate against the LMFBR.

(g) Environmental Aspects

The lower steam conditions of the CANDU-PHW result in a lower station efficiency and hence greater heat rejection to the condenser cooling source. The availability of various large sources of cooling water in Ontario has prevented this from being a significant problem. The CANDU-PHW is at an advantage as far as radioactive wastes are concerned since reprocessing of the spent fuel is not a requirement for economic viability.

(h) Safety and Licensing

The PHW meets all current Atomic Energy Control Board licensing requirements. The non-CANDU reactor types have never been licensed in Canada and this lack of previous experience would place them at a disadvantage in the Canadian context.

(i) Costs

Fuel cycle capital costs are clearly low for a natural uranium system. This is somewhat off-set by the requirement for the heavy water which makes the natural uranium cycle possible. The capital costs of

the PHW and LWR plants are much closer than the ranking given in the table would indicate. Total energy costs depend on the generating site, local conditions, the cost and availability of capital and many other commercial considerations. Generalizations can therefore be misleading. However, in the Canadian context, the CANDU-PHW has proven to be a sound economic choice.

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2.1.2 Occupational Radiation Safety

Occupational radiation safety in Ontario Hydro's nuclear power program is a defined responsibility for four segments of the organization: the individual employee, an independent health and safety authority, operations, and design. The placement of the prime responsibility on the trained employee is an extension of Ontario Hydro's long established practice in conventional safety where it has proved effective in dealing with our major industrial hazard, electrocution.

2.1.2.1 Health and Safety Division Responsibilities

The Health and Safety Division through its Health Physics Department is responsible for the establishment and on-site supervision of policy and regulations for occupational radiation safety. This is formally documented in the Ontario Hydro Radiation Protection Regulations (1), which the Department prepares and submits to the Atomic Energy Control Board for approval. It is also responsible for the training of station staff (2,3) in the science fundamentals of radiation protection, and the qualification of all station personnel, therein. Employees are made aware of the potential risks involved in working with radioactive materials, and are taught how to minimize these by minimizing radiation exposure. The Health Physics Department formally grants employees access to operating areas as a function of the level of radiation protection training attained. Achievement and maintenance of the required standard of competence is a condition of employment. This department also provides on-site analytical services at the stations to measure and record all occupational radiation doses from both external and internal sources.

2.1.2.2 Operations Branch Responsibilities

The Nuclear Generation Division is responsible for carrying out those physical measures required within the stations for the control of radiation exposure and is accountable for regulatory bodies in this respect. It is its responsibility to administer and apply the Radiation Protection Regulations and to establish Radiation Protection Procedures (4) in accordance with them. This division independently trains and qualifies station personnel in these procedures.

The division includes central, technical service groups involved in the assessment of station performance and design or procedure modifications in many areas, including those that have or could potentially have an effect on occupational radiation safety. Various station records documenting radiation safety conditions are maintained, and annual reports of station performance are prepared for the regulatory authorities. The latter reports include changes in personnel and procedures, equipment modifications, unusual occurrences, and test results. Any unusual occurrence or sequence of occurrences which led, might have led, or might lead to any person receiving a dose in excess of the regulatory standards is promptly reported.

2.1.2.3 Design and Development Division Responsibilities

Within the Design and Development Division, a specialized group is engaged in the establishment of design standards for radiation safety systems, occupational dose, and shielding. Actual design is carried out by various project engineering and design departments. Typical safety systems include access control systems within the station areas, alarming area monitors, and continuous air monitoring systems. They are assisted in establishing these standards by the Health and Safety and Nuclear Generation Divisions. This design group provides a radiation safety advisory service to project engineering and design departments, carries out day-to-day design verification, and implements formal radiation dose design audits (5). This program is an integral part of the engineering quality assurance program.

The assessment of alternative design concepts against radiation safety design objectives is carried out through the conceptual, preliminary and detailed engineering phases.

The design audit process numerically estimates the annual station dose at maturity and identifies the operational and maintenance activities that may involve significant occupational doses. This includes considerations such as the buildup of radiation fields with time, and the benefits gained by periodic total system decontaminations, which have been demonstrated at the Nuclear Power Demonstration and Douglas Point Generating Stations.

2.1.2.4 Co-operative Program

Close cooperation exists among the above three divisions to maintain a dynamic radiation exposure control program emphasizing in-plant and design awareness of radiation and contamination conditions. Its objectives are to prevent acute doses, to reduce unnecessary doses, and to keep occupational exposures within the regulatory limits. Typical considerations include:

1. Design, selection and location of equipment to minimize servicing frequency and time in radiation fields.

2. Provision for the movement of equipment to lower radiation field areas for maintenance.

3. Careful selection of reactor materials, including trace impurities, to minimize the production of radioactive corrosion products, particularly long-lived ones, on exposure to neutron radiation.

4. Selection of valves, packing materials, and gaskets to minimize leakage, replacement frequency, and replacement working times in high dose rate areas.

5. Segregation of radiation sources such as pumps, pipes, ducts, tanks, etc. containing radioactive materials.

6. Establishment of design dose rate criteria for various station areas as a function of accessibility relative to reactor state, i.e. shutdown vs. operating, and expected occupancy.

7. Provision of shielding consistent with the intent of keeping occupational doses "as low as reasonably achievable".

8. Provision of permanent shielding, where practicable, between radiation sources and areas to which personnel have normal and routine access.

9. Utilization of movable shielding and associated handling facilities where permanent shielding is needed but impractical.

10. Design of shielding to limit potential voids and minimize exposure in the vicinity of pipe and duct penetrations.

11. Application of remote handling equipment wherever it is needed and is practicable. Care must be exercised that the maintenance of such equipment is not a greater man-rem liability than the original problem.

12. Design of system layout and surfaces to minimize contamination buildup, and to facilitate flushing or remote chemical cleaning prior to maintenance.

13. Precautions to minimize the spread of contamination, and to facilitate decontamination when spillage occurs.

14. Provision of a ventilation system designed to ensure control of airborne contaminants, especially during maintenance operations when the normal air flow patterns may be disrupted.

15. Ventilation system design features that cater to easy access and servicing during filter changes, maintenance, decontamination and alterations.

16. Location of instruments requiring in-situ calibration in the lowest practicable radiation fields.

17. Location of system sampling locations so that personnel exposures resulting from routine sampling of active systems will be "as low as practicable".

2.1.2.5 Radiation Dose Limits and Targets

Maximum Permissible Radiation Doses for atomic energy workers are specified in the Atomic Energy Control Regulations (6), and are based on the recommendations of the International Commission on Radiological Protection (ICRP)(7). These statutory dose limits are not regarded as design targets, but rather as maximum values. Ontario Hydro is committed to the ICRP recommendation that all radiation exposures be maintained as low as reasonably achievable, economic and social factors being considered. Specifically, Ontario Hydro's design objective is that a station be operated and maintained at maturity by its normal

staff complement, or the occupational dose equivalent of that normal staff complement.

2.1.2.6 Ontario Hydro Experience

In 1974, the four unit Pickering station had an occupational dose (8, 9) performance index of 1.1 rem per megawatt-year of electrical energy produced. This was despite the major abnormal maintenance program requiring replacement of pressure tube fuel channels which resulted in both increased occupational doses and decreased energy production. Without this task, the index would have been about 0.8 rem/MWe.y.

In terms of severe injury or death, the radiation safety record in nuclear power stations exceeds the performance of even the safest industries reported by the National Safety Council. In the western world's civilian nuclear stations, there has yet to be a fatality or serious injury as a result of high radiation exposure. The potential for delayed effects is discussed in Section 2.3.2.2.

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2.1.3 Nuclear Generating Station Safety

2.1.3.1 General

Ontario Hydro has a responsibility to protect the public and its staff from any potential hazards associated with use of nuclear energy for the production of electricity. To meet this responsibility, measures are taken during the design, construction and operation of its nuclear facilities to minimize the possibility and consequences of incidents which could result in the release of hazardous material. Because of the large inventory of radioactive material in a nuclear reactor, careful attention is paid to providing features which will ensure that this radioactive material can not escape to the public.

2.1.3.2 Safety Philosophy - Defense in Depth (1,2)

CANDU reactors contain an array of natural uranium fuel physically located to ensure an efficient fission process and from which any rearrangement, for example by accident, would reduce the efficiency and shut down the fission process. This is the reverse situation from the design of nuclear explosive devices where highly enriched fuel must be brought together in a very specific arrangement to cause a nuclear explosion.

High quality, reliable process systems, designed to regulatory codes and standards, are provided, which will minimize the possibility of a release of radioactivity. These process systems control the heat generation and heat removal from the fuel under all normal operating conditions, including a wide range of operating transients. In addition, the stations contain engineered safety systems which act to limit the consequences of any unlikely event with the potential for the release of radioactivity. These systems operate to (a) rapidly shut down the nuclear fission process when limiting operating conditions are exceeded; (b) safely remove thermal energy from the reactor system and; (c) prevent the release of radioactive material in excess of regulatory limits under the most severe postulated conditions.

An additional safety factor is the provision of an exclusion zone around nuclear generating stations which extends to a radius of 915 metres (3,000 feet).

In this exclusion zone, no permanent habitation is permitted.

2.1.3.3 Role of Atomic Energy Control Board (3,4,5,6)

Under the Atomic Energy Control Act and Regulations, the Atomic Energy Control Board (AECB) has responsibility for the health and safety of the public as a result of the operation of nuclear facilities. The Ministry of Health of the Province of Ontario also has a responsibility for public health and safety in particular with respect to the establishment of contingency plans. In meeting this responsibility, the AECB establishes limits for radiation doses to the public during normal and abnormal nuclear station conditions. These limits are established based on extensive on-going studies carried out by international bodies such as the International Committee on Radiological Protection and the International Atomic Energy Agency. These agencies, made up of world authorities in the fields of radiation and nuclear safety, have developed criteria based on many years of study and are continuously reviewing the safety criteria.

The AECB issues licences for construction and for operation of the nuclear station when they have reviewed the detailed design information and analysis of postulated accident situations submitted by Ontario Hydro, and are convinced that adequate safety will be provided. Once a facility is in operation, AECB staff continuously inspect and monitor plant performance and are kept informed of all safety related events.

2.1.3.4 Licensing Criteria - Canadian Safety Philosophy (1,5,7)

The critical process systems in nuclear stations are designed specifically to meet quantitative reliability standards - their failure rate must be low. Engineered safety systems are also designed to high reliability standards, incorporating multiple redundant fail-safe components.

In spite of the low probability of failures, overall plant safety design is such that nuclear stations are tolerant to a wide range of postulated failures in both the process and safety systems. During plant design, a spectrum of process failures, including hypothetical extreme failures, are examined. The consequences of these failures are defined in detail and compared to conservatively established

radioactivity release criteria. In addition, each of the engineered safety systems are in turn postulated to be unavailable coincident with each process failure. The consequence of these postulated dual failures are also required to be within established release criteria.

2.1.3.5 Accident Analysis (7,8,9)

A typical process failure that is analysed in following the above approach, is a failure of the reactor control system. Because the reactor control system is complex, containing many control devices and regulatory control loops, the limiting case is examined. That is, all control devices are driven at maximum rate in the direction which increases reactor power. In addition, each shutdown system is in turn postulated to be unavailable during this transient; the available shutdown system must be fully capable of safely terminating the incident. Other process failures which are examined include pump trips, loss of electrical power and pressure tube rupture.

The limiting process failure, which sets the requirements for the safety systems (shutdown systems, emergency core cooling system, containment system) is a postulated heat transport system pipe rupture or loss of coolant accident (LOCA). A major piping failure causes:

(i) a power increase due to positive reactivity caused by steam formation in the reactor - this requires the shutdown systems to act,

(ii) eventual decreased cooling on the fuel - this requires the addition of water from the emergency core cooling system to maintain cooling to the fuel, and

(iii) the release of energy to the building via flashing coolant - this brings the "vacuum building" into action.

The loss of coolant accident is analysed in detail to ensure that the release of radioactivity does not exceed conservative limits specified by the AECB. In addition, each safety system is assumed to be coincidentally impaired; the release in these cases must be below the "dual failure" release limit specified by the AECB. For example, the emergency core cooling system is assumed unavailable and the containment must limit the release; the containment

system is assumed impaired, (e.g. a hole in containment) and the combined action of the remaining systems must limit the release.

The above analyses of a hypothetical major pipe rupture reflects the defence in depth philosophy and provides a high degree of assurance that the public is protected against a major release of radioactivity.

2.1.3.6 Risk Assessment (5,10)

Risk involves both the likelihood of occurrence and the consequence of an event. Both of these have been assessed from the outset in the Canadian approach to the assessment of potential accidents in nuclear power stations. Accident analyses show that for single and dual failure, the CANDU stations operating and under design and construction are within the radioactivity release criteria established by the AECB. In addition, the estimated frequency of significant events is very much below the criteria in the siting guide.

To obtain some feel for the public risk involved in developing nuclear power it is helpful to compare the risks to other non-nuclear risks to which our society and its individuals are already exposed. Recent studies by Dr. N. Rasmussen of accident risks from potential accidents to United States reactors provide a useful illustration of the low level of risk involved in the nuclear program. The frequency of a variety of events is shown in the following table. It is Ontario Hydro's belief that the risk from CANDU reactors would be at least as low as the U.S. light water reactors.

Risk of Fatality by Various Causes*

	Individual Chance per Year
Motor Vehicle	1 in 4,000
Falls	1 in 10,000
Fires	1 in 25,000
Drowning	1 in 30,000
Air Travel	1 in 100,000
Electrocution	1 in 160,000
Lightning	1 in 200,000,000
Nuclear Reactor Accidents (100 plants)	1 in 5,000,000,000

*U.S. data from Reference 10.

2.1.3.7 Reliability and Testing of Safety Systems

Reliable designs of both process and safety systems are achieved by the application of quantitative reliability techniques. During the operation of nuclear stations, equipment performance is continually monitored by a program of in-service inspection and scheduled routine testing. The results of the test program are documented and submitted at least annually to the AECB. These test results include in-depth examination of any significant component failure in safety systems, including their overall effect on the system performance.

2.1.3.8 Ontario Hydro Experience

No incident has ever occurred in Ontario Hydro (or any operating commercial nuclear generating station) in which a member of the public has received a radiation dose in excess of, or indeed even approaching, regulatory limits.

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9. Safety Report

   Issued by Ontario Hydro to Atomic Energy Control Board to support applications for licenses to construct and operate a nuclear power plant. It contains comprehensive information about the proposed facility, its operating conditions, and its environment. It describes the design of the plant, safety provisions, and the design criteria of the system. This report is updated each year.

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6. Off-Site Contingency Plan for the Pickering Nuclear Generating Station, (Ministry of Health, Ministry of the Environment, Ministry of the Solicitor General, Ministry of Agriculture and Food, Ontario Hydro), February 26, 1974.

   This Plan describes the actions to be taken by the Agencies listed above, in the Province of Ontario, in the event of a radiation incident occurring at the Pickering Nuclear Power Station as a result of which the public outside the limits of the plant may be affected by radioactive material.

   The present plan is concerned with actions which may be necessary after direction of off-site measures is taken over by the Ministry of Health from Ontario Hydro, and is coordinated with the plans of the responsible municipal authorities.

7. Standards Produced by the Canadian Standards Association, such as

N285.1-1975	-	General and Construction Requirements for CANDU Nuclear Power Plant Components
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pN287.1-1975	-	General Requirements for Concrete Containment Structures for CANDU Nuclear Power Plants
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pZ299.2-1975	-	Quality Control Program Requirements
pZ299.3-1975	-	Quality Verification Program Requirements
pZ299.4-1975	-	Inspection Program Requirements

where p stands for preliminary standards.

8. Atomic Energy Control Board Licensing Guides Produced by Atomic Energy Control Board to outline quidelines to be followed in the detailed design and/or operation of safety and related systems/procedures.

9. American Society of Mechanical Engineers (ASME) Guides

10. Institute of Electrical and Electronics Engineers (IEEE) Guides.

2.1.4 Heavy Water Production Plant Safety

Ontario Hydro heavy water production plants contain substantial quantities of hydrogen sulphide gas which is toxic. (There are no chemical or radiological hazards associated with the end product, heavy water.) To meet its responsibility with regard to public safety, Ontario Hydro incorproates features into the design and operation of its heavy water plants to prevent or mitigate the consequences of the accidental release of hydrogen sulphide.

2.1.4.1 Safety Features

1. Systems and equipment used to control the process are designed and constructed to petrochemical industry standards. They also meet the specific regulatory codes and standards applicable to heavy water production plants. These systems and equipment ensure that plant operation is maintained within predetermined safe limits.

2. Isolation circuits are provided which minimize the release of hydrogen sulphide should a leak develop in the pressure boundary.

3. Regular inspection of piping and pressure vessels is carried out to ensure that no significant deterioration is occurring.

4. Well-trained operating and maintenance staff are available to ensure that all systems are kept in a reliable condition.

5. Emergency procedures are established and staff are trained and equipped to deal with emergency procedures should they occur.

6. A controlled zone, with low population density, is established within a 5-mile radius of the plant (1). (In comparison, nuclear generating stations require an exclusion zone with a radius of 3,000 feet.)

7. In summary, design and operation must meet standards of safety which go significantly beyond those imposed on the general petrochemical industry handling the same material.

2.1.4.2 Role of the Atomic Energy Control Board (2)

The potential hazards associated with heavy water production plants are almost exclusively due to the toxic chemical hydrogen sulphide. Nevertheless, since heavy water is a prescribed substance, the Atomic Energy Control Board (AECB) under the Atomic Energy Control Act (3) and Regulations (4), has responsibility for the health and safety of the public as a result of operation of heavy water production plants. All nuclear facilities, including heavy water plants, are therefore licenced and regulated by the AECB. They issue construction licences only when they are assured that all relevant safety regulations can be met. Design and construction progress is monitored to ensure that detailed design meets all safety criteria. Prior to operating the plant, the AECB will have reviewed the complete design in detail, including analyses which describe plant behaviour under a range of severe accident conditions.

The AECB also receives advice from a Safety Advisory Committee set up for each heavy water plant. This committee consists of federal, provincial and local experts in various fields. It makes recommendations on the suitability of any heavy water plant before it is constructed or operated.

When the plant is ready for operation, an operating licence is issued by the AECB which stipulates conditions under which the plant is to be operated to ensure continuing safety during its operating lifetime. Once a facility is in operation, AECB staff officers inspect and monitor plant performance to ensure adherence to the stipulated conditions. The AECB staff officers receive annual reports which describe plant operation and they can demand reports on any event or occurrence that they consider to be significant or unusual.

2.1.4.3 Ontario Hydro Experience

Ontario Hydro presently operate a Heavy Water Production Plant at the Bruce Nuclear Power Development with expansion of this facility underway. There has never been release of Hydrogen Sulphide which approached a level which could cause a public hazard.

Some minor leakages have occurred which have caused detectable "odours" in public areas. While these are

not hazardous levels, Ontario Hydro recognizes a responsibility to reduce the frequency of occurrence of such nuisance incidents. To that end, records are kept of all off-site indications of "odours", each one is followed up to determine the cause, and appropriate action is taken to prevent or minimize its reoccurrence. In addition, general improvements have been incorporated in the existing and future plants as a result of operating experience. Significant improvements have been noted; frequency of occurrence of off-site "odours" has decreased from 50/year in 1973 to 4/year in 1975.

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2.1.5 Low and Medium Level Radioactive Waste Management

The radioactive solid byproducts produced in a nuclear generating station can be divided into two broad categories: spent fuel, which is technically not considered a "waste" since it contains valuable fertile and fissile materials, contains over 99% of the radioactive material produced in a nuclear station; and the remainder of the solid radioactive byproducts, termed medium and low level wastes (1). Spent fuel management is discussed in Section 2.1.6.

2.1.5.1 Medium Level Waste

The medium activity wastes consist primarily of filter media, water purification resins, solidified liquid concentrates and reactor core components, and account for over 90% of the radioactivity, excluding spent fuel, that has to be managed. Typically, the filter media are contained in disposable 0.15 m^3 pressure vessels although some filter cartridges are removed from their vessels and handled separately. Solidified liquid concentrates are contained in disposable 0.2 m^3 steel drums. Radioactive resins are either contained in disposable 0.15 m^3 pressure vessels or are stored in large vessels located within the generating station. These medium level wastes generally require radiation shielding while they are being handled in-station and require special shipping packages ("overpacks") for shipment to the central waste storage facility.

2.1.5.2 Low Level Waste

Low level wastes, which comprise 95% by volume of all medium and low level wastes, include miscellaneous slightly radioactive, housekeeping materials such as paper and plastic sheeting, mops, rags; scrap materials and used protective clothing. Also, inactive wastes collected in zones of the station where radioactive materials may be present are treated as radioactive. These low level wastes are generally wrapped in 0.06 m^3 polyethylene bags or plastic sheeting and are placed in 0.2 m^3 steel drums or larger (1 m^3) steel containers for shipment to the waste storage facility.

2.1.5.3 Transportation of Low and Medium Level Waste

Road transport of medium and low level wastes to the central storage facility, located in the Bruce Nuclear Power Development (Bruce NPD), is subject to the Atomic Energy Control Regulations (SOR/DORS/74-334). These regulations, which also govern packaging and loading requirements, are essentially identical to the International Atomic Energy Agency (IAEA) Regulations for the Safe Transport of Radioactive Materials (2). Generally, medium level wastes are transported in "Type B" packages which are individually licenced by the regulatory authorities and are designed to withstand accident conditions of transport with only a very limited reduction in containment and shielding efficiency (Section 2.1.6.6). Low level wastes are shipped in "Type A" packages which are designed to withstand the normal conditions of transport but may be damaged in accidents. The amount of radioactive material that may be shipped in these packages is strictly limited and is based on consideration of radiological consequences of potential accidents.

The considerable experience that has accumulated in the road and rail transport of radioactive wastes provides assurance that the safety objectives of the shipping regulations are being achieved (3).

2.1.5.4 Waste Storage Facilities

Within the Bruce NPD there are two waste storage sites for medium and low level wastes: Site 1 is essentially full and is no longer actively being loaded; Site 2, which covers an area of approximately 0.077 km^2, is in the early stages of development. Development and operation of waste storage facilities, and other associated facilities, is regulated by the Atomic Energy Control Board (AECB) (4).

Ontario Hydro's current practice is to store, not dispose of, these wastes in facilities (e.g. reinforced concrete structures) that incorporate double barrier engineered features to isolate the wastes from the biosphere. Hydrogeologic features of the waste storage site serve to "back-up" the engineered containment capability. Only solids, not liquids, are placed in storage and no wastes are placed directly into soil. A "radioactive" incinerator is presently under construction at Site 2 and will be used for incineration of the large

Utility	Installed Gen. Capacity Gas Turbine	Installed Gen. Capacity Plant	No. of GT	Nameplate Rating GT	Mgfr & Model	Scheduled In-Service Date
16. Southern California Edison						
Huntington Beach 6A,6B,7A,7B,9A,9B	432	-	6	72	-	1978
9A,9B,10A,10B,11A	432	-	6	72	-	1979
11A						
Long Beach 1A,2A,	430	-	7	60	-	1976
3A,4A,5A,6A,7A						
Lucerne Valley	922.5	-	15	61.5	GE STAG 500	1980/81
Subtotal	3635.78 1389.4		56 26			
TOTAL	5025.18		82			

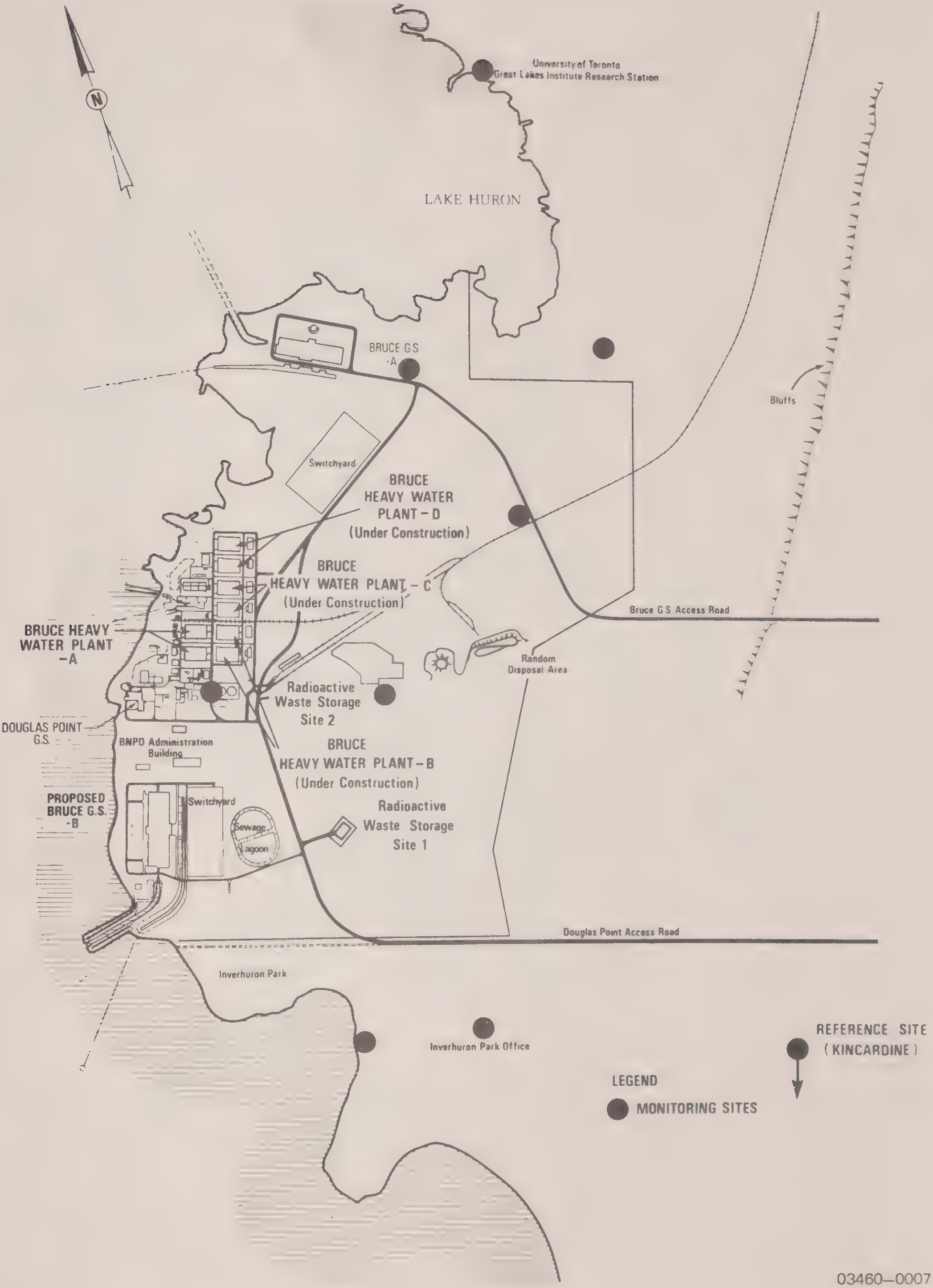


FIGURE 2.1.5-1 BRUCE NUCLEAR POWER DEVELOPMENT WASTE STORAGE AND ENVIRONMENTAL MONITORING SITES

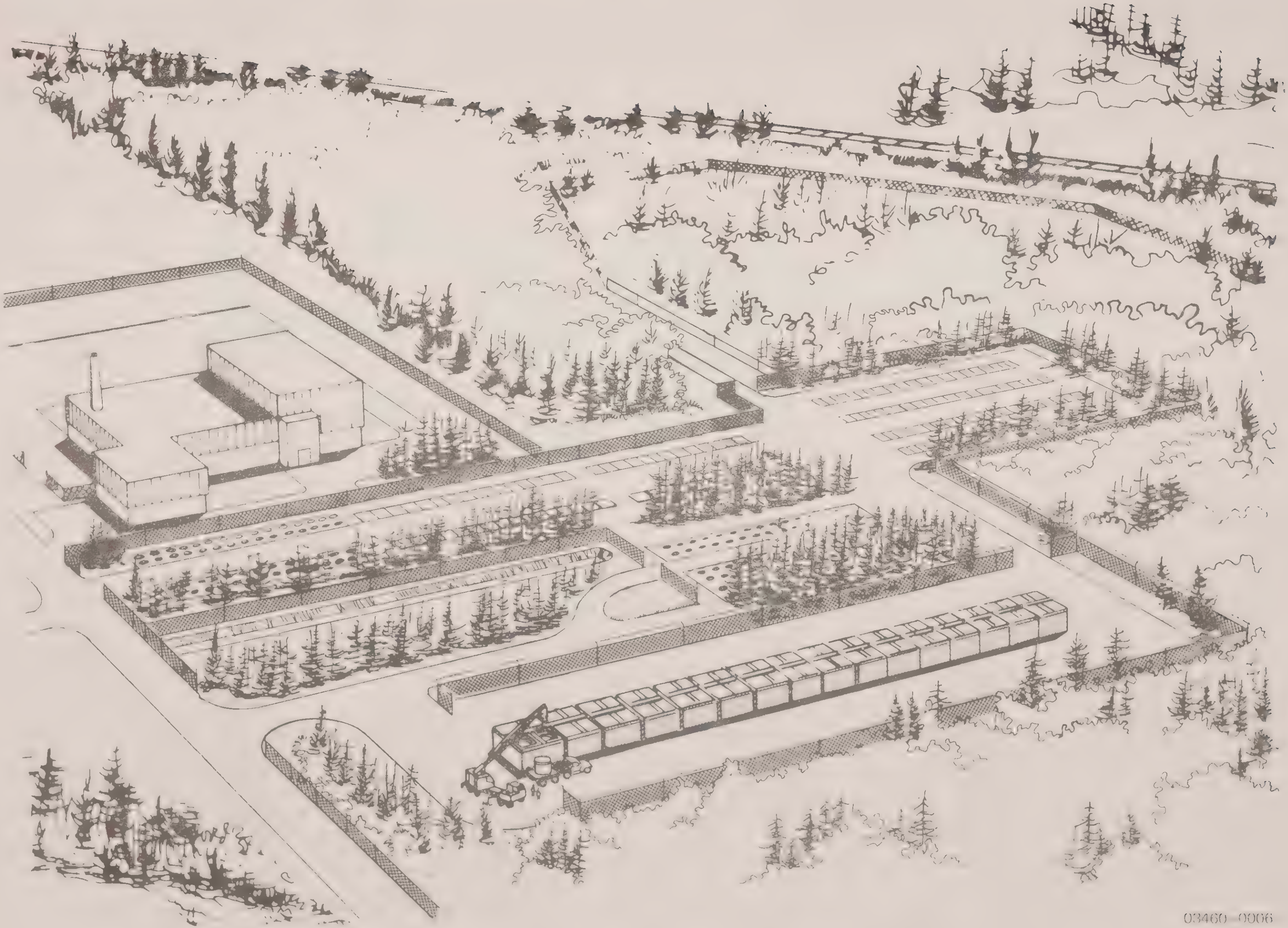
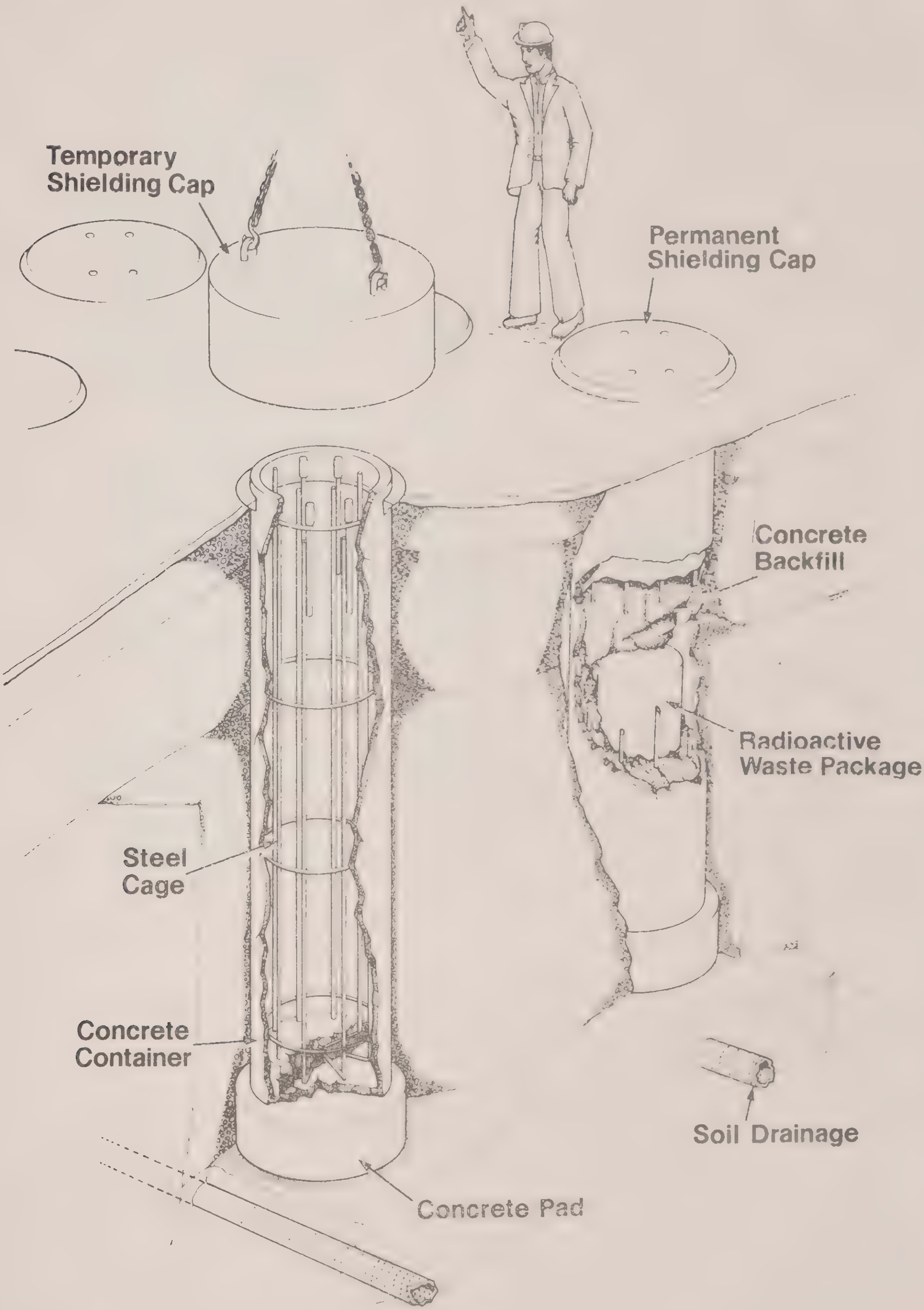


FIGURE 2.1.5–2 SKETCH OF WASTE STORAGE SITE 2

FIGURE 2.1.5–3 RADIOACTIVE WASTE TILE HOLE



quantities of slightly radioactive combustible wastes. Radioactivity monitoring of the exhaust gases will ensure that releases are within design and operating targets for airborne releases from nuclear facilties (Section 2.3.2.1). All ash will be placed in the radioactive waste storage structures.

The waste storage site is subject to ongoing operational and environmental monitoring. Particular emphasis is placed on groundwater and surface water sampling because this represents the major potential pathway for activity escape from storage facilities. These monitoring provisions, which include perimeter sampling wells and subsurface drainage systems, ensure detection of any radioactivity escape from the facilities well in advance of it entering the public domain.

It is recognized that the timespan of concern (more than 100 years) for some of the medium and low level radioactive wastes may be longer than the lifetimes of these storage facilities. For this reason, all such wastes are stored only in a retrievable manner. Long-term care of the facilities, including transfer of some wastes to replacement facilities, as necessitated by facility degradation, may be required, and is part of the waste management plan.

2.1.5.5 Ontario Hydro Experience

Ontario Hydro has approximately 8 years experience in the operation of waste storage facilities at Bruce NPD and throughout this time there has never been an occurrence or situation which posed any radiological hazard to the public.

FIGURE 2.1.5–4 RADIOACTIVE WASTE CONCRETE TRENCH

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Line Number

2.1.6 Spent Fuel Management

2.1.6.1 Introduction

Natural uranium fuelled CANDU nuclear generating stations operated to produce base-load electric energy, discharge approximately 140 kg (6 bundles) of spent fuel per year per MWe of installed capacity. The spent fuel represents an important potential energy resource for the future since it contains most of the uranium in the original natural uranium fuel plus fissionable plutonium formed during its residence in the nuclear reactor. The spent fuel also requires careful management since it contains almost all of the radioactive products (in excess of 99 per cent) produced in the operation of power reactors. This must ensure that the contained radioactive products and plutonium are maintained under close control, separate from man's direct environment, and that maximum future benefit is derived from this energy resource.

A multi-discipline study group of Ontario Hydro and Atomic Energy of Canada Limited personnel have for the past two years been investigating various aspects of the control and use of spent fuel and have formulated a long range plan for the management of this material. This proposed plan is under active consideration by senior management of both organizations at present.

Evaluation of this plan requires an understanding of the various potential hazards, concerns, and benefits associated with spent fuel, and the status of the technology upon which the plan is based. The following sections discusses briefly the proposed Ontario Hydro plan and the potential areas of concern with regard to spent fuel.

2.1.6.2 Ontario Hydro's Proposed Spent Fuel Management Plan

Ontario Hydro's proposed plan for the management of the spent fuel produced by its nuclear generating stations, covers four main phases. The first phase is to store the spent fuel bundles discharged from the reactors in water filled storage bays at the nuclear generating station sites for a period of about five years. During this time the gamma radiation emitted by the spent fuel and the rate of heat production by the fuel will each have decreased by a hundredfold or more from the levels at one hour after discharge from the reactor.

The second phase of the plan is to ship the spent fuel bundles from the station storage bays after five years' storage there, to a single, central, interim storage facility. Here the spent fuel will be stored until it is reprocessed to recover its plutonium content, or until it is packaged in a form suitable for long term disposal. It is proposed that spent fuel from all of the Ontario Hydro nuclear generating stations will be stored at a single, central, interim storage facility.

The third phase of the Ontario Hydro plan for management of spent fuel is to reprocess the spent fuel from the interim storage facility to recover its plutonium content and then to package the radioactive wastes from this operation in a form suitable for placement in a radioactive waste disposal facility. This will require that the radioactive waste be immobilized by fixation in a glass or ceramic matrix prior to disposal. This third phase of the Ontario Hydro plan may be modified if recovery of the plutonium in spent fuel is not required. In this event the reprocessing operation would be eliminated and the spent fuel, complete with its plutonium, would be packaged in a form suitable for ultimate disposal. It is unlikely that plutonium from spent fuel will be recycled for many years since prior extensive investigations and development will be required. Therefore, the central interim storage facility will probably have a life of twenty-five or more years.

The fourth phase of the plan is to place the packaged radioactive waste from the reprocessing plant or the unprocessed spent fuel, into an ultimate disposal facility. This facility will be located deep underground in geologically stable strata. For example granitic rock which has been stable for two billion years. The material placed there will be isolated from man's environment, and will be immune from such natural phenomena as recurring ice-ages. Initially the material will be stored in a retrievable mode. Once it has been satisfactorily established that the facility will achieve its long term isolation objective, and the stored material has no potential value, the retrievability features will be terminated to provide even greater assurance of its separation from man.

The spent fuel management plan described above and shown in Figure 2.1.6-1, is primarily based on the three following objectives:

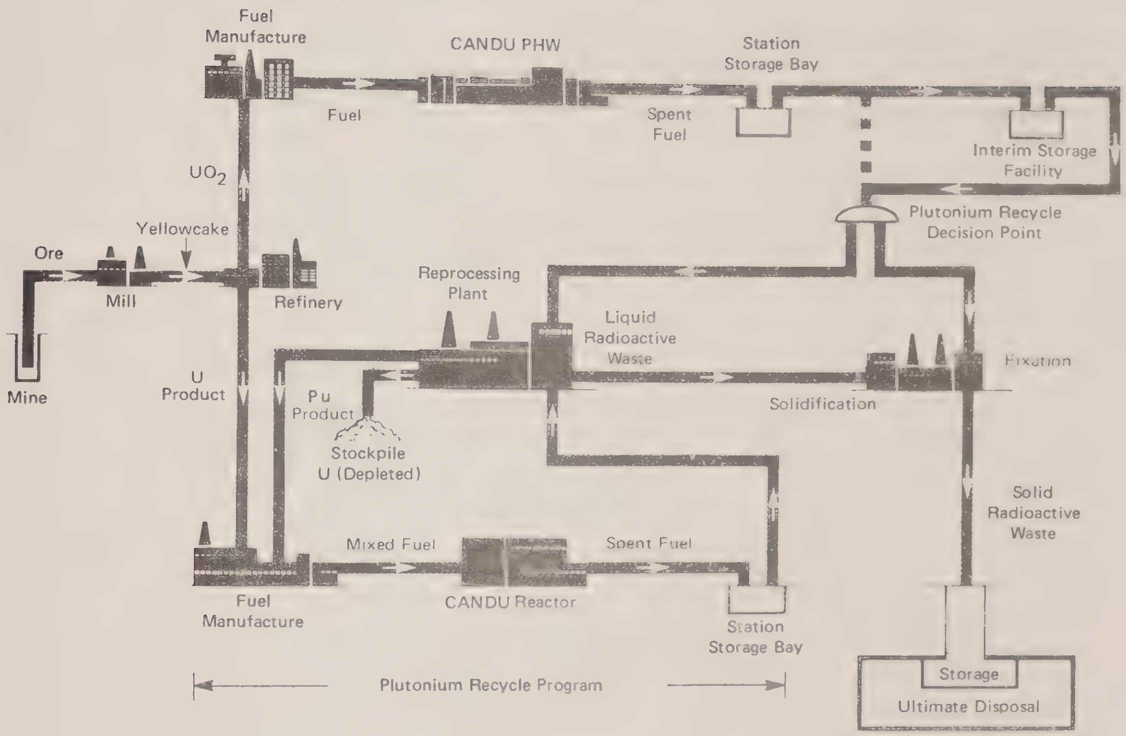

Figure 2.1.6–1
Possible CANDU Fuel Cycle

(1) Safety Objective - Radioactive byproducts and wastes must be managed in such a manner that they will not be harmful to man over the lifetime of their hazardous nature. This means that they have to be effectively separated (isolated) from man's environment for this time.

(2) Responsibility Objective - High-level radioactive byproducts and wastes must be managed so that they will remain separated from man's environment over their hazardous lifetime even though knowledge of their existence may be lost.

(3) Current Technology Objective - Techniques used to meet the safety and responsibility objectives must use technology that is known at present, or that can be developed at this time.

2.1.6.3 Potential Hazard of Spent Fuel (1,2,3,4)

Spent fuel contains radioactive material that represents a potential hazard to man. The spent fuel basically consists of two groups of materials, namely fission products, and actinides. The radioactivity of these two groups decay with time as shown in Figure 2.1.6-2. In less than 1000 years, the fission products generally decay to isotopes that are not harmful to man. After a timespan of the order of one million years, the actinide group of radionuclides in spent fuel will have decayed to uranium and its daughter products. These in turn decay to lead. This period is far beyond the experience of man, although it is a relatively short period in geologic time.

The potential hazard to man and his environment from spent fuel is the result of the radiation emitted by the unstable nuclides that are present. The effect of this radiation on man may be due to radioactive material that is external to the body, or to material that enters the body through ingestion or inhalation.

External Radiation

Spent fuel emits alpha, beta, gamma and neutron radiation especially in the early cooling period. This radiation decreases in intensity with time. The main penetrating external radiation is the high energy gamma activity of the fission products which is significant for several hundred years. Water and

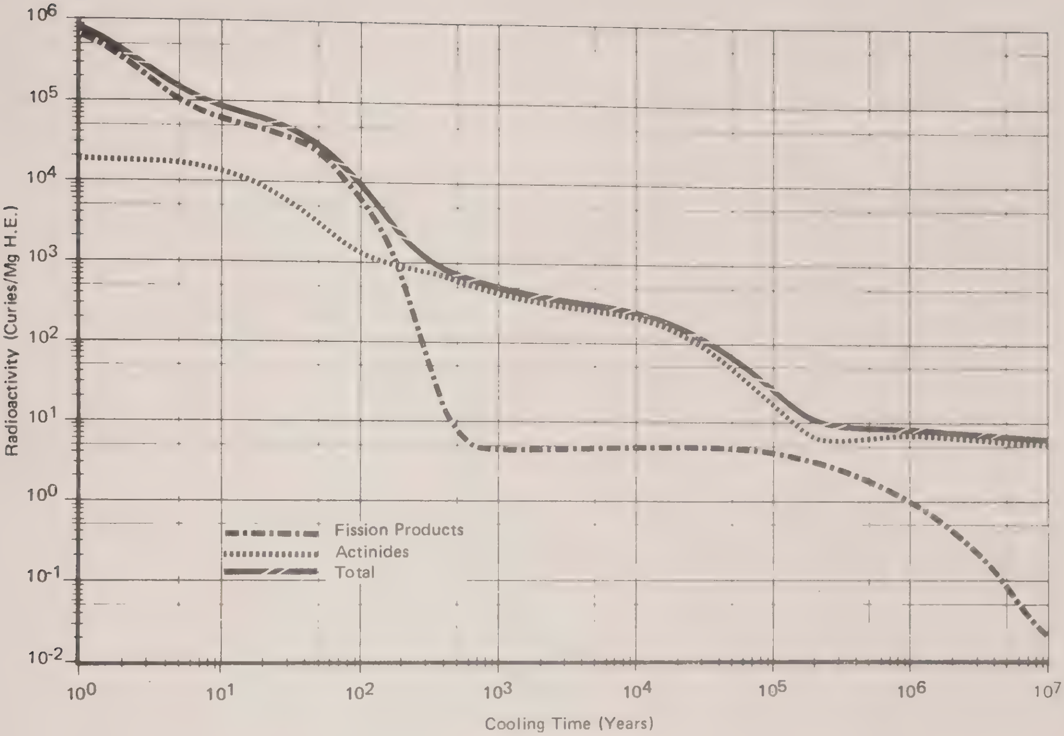

Figure 2.1.6–2
Fuel Radioactivity—Pickering Reference Fuel
(Average Exit Burnup of 7500 MWd/MgU)

concrete are effective materials for shielding against this gamma radiation and the plan discussed previously includes the installation of storage facilities constructed of these materials to provide effective shielding.

Internal Radiation

Alpha and beta particle radiation associated with the isotopes of plutonium constitute the main potential hazard due to material that enters the body. The effect of this material, however, depends on its chemical form and the method by which it enters the body. For example elemental plutonium or plutonium compounds present a much more serious potential hazard if inhaled as compared to the effect if the material is ingested. Since the plutonium in spent fuel at normal temperatures is in solid form, inhalation is extremely unlikely.

The other pathway for plutonium uptake by man is by ingestion through the food chains. The plan discussed previously includes engineered barriers to prevent plutonium from entering the food chain. Should plutonium escape from these engineered barriers, natural environmental retention mechanisms (such as impermeability and ion-exchange properties of soils and rocks) and the chemical and physical properties of plutonium, will tend to diminish the potential hazard.

2.1.6.4 Technology Base (5,6,7,8)

The four phases of the spent fuel management plan include the provision of facilities to store the spent fuel in a manner that will adequately provide protection for members of the public and the environment. The knowledge upon which this plan is based exists in differing degrees for the various phases of the plan. For example, the storage of spent fuel under water in bays at reactor sites has been undertaken successfully for about 25 years.

Known technology has been used to develop conceptual designs for the interim storage facility and preliminary studies of these designs have shown that their environmental effects are expected to be mainly due to normal construction activities. The concept of interim storage in water filled pools shown in Figure 2.1.6-3, is an extension of the experience obtained from the storage in pools at the station sites. While the work on the interim storage

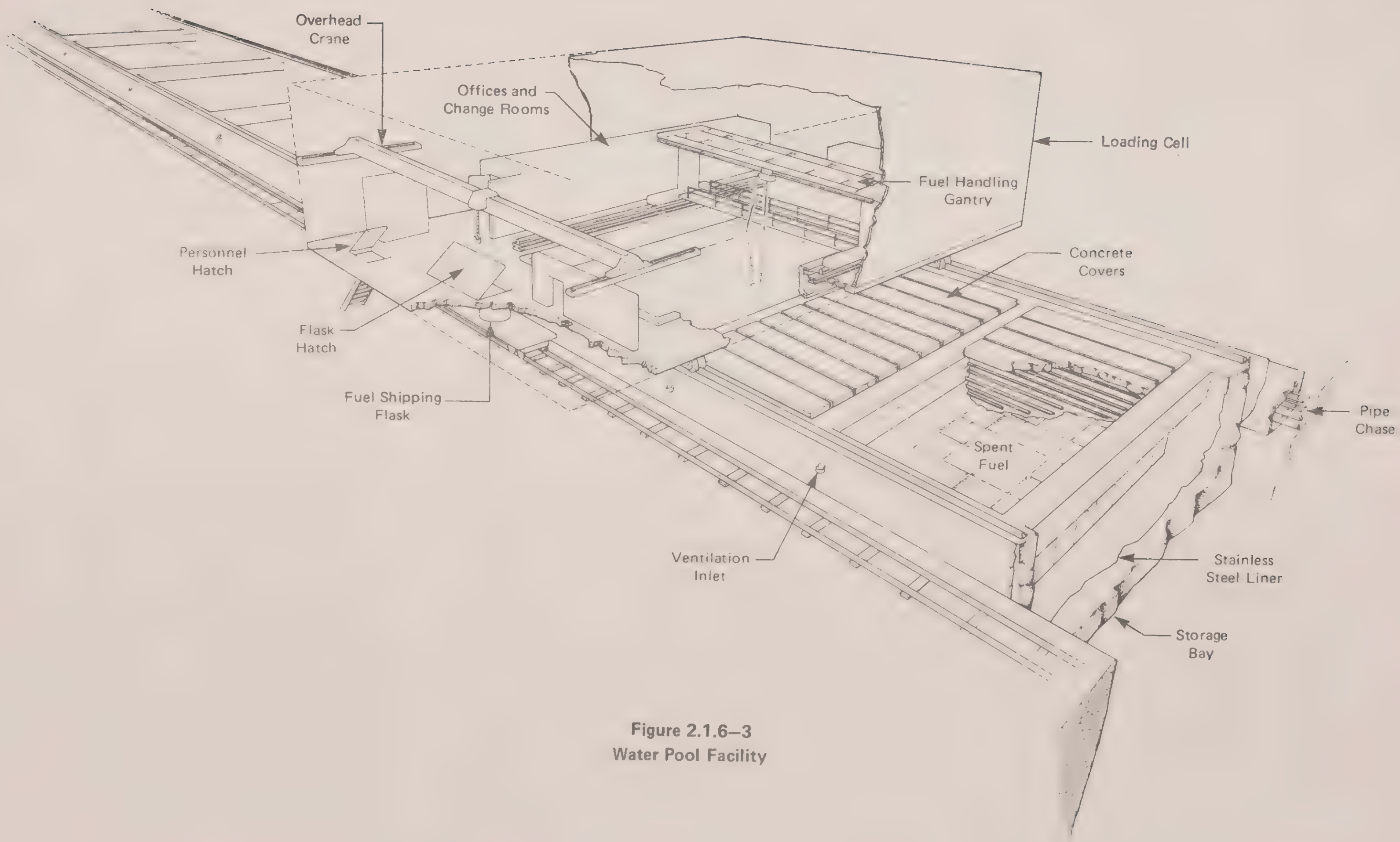

Figure 2.1.6–3
Water Pool Facility

facility is not yet complete, the work undertaken so far is on a well established base of technology.

Processing of spent fuel to recover its plutonium if desired or to package the radioactive waste for disposal, has not been undertaken in Canada except for some laboratory scale work. Industrial reprocessing of spent fuel has been undertaken in the United States and Europe. Information readily available in Canada is not yet sufficient to assess with much confidence, the environmental effects of such processing operations although assessments of environmental effects have been undertaken in the United States.

The environmental effects of the disposal of radioactive waste deep underground in geologically stable strata, have not been evaluated in Canada. Programs are underway to obtain the information required to undertake this evaluation.

The assessment of the effect on the environment of the processing of spent fuel and of the disposal of the waste deep underground, will be undertaken in detail as part of the spent fuel management program. Ontario Hydro's experience in the area of radioactive waste management and the status of mining technology in Canada and abroad, gives promise that these phases of the spent fuel management plan can be undertaken successfully.

2.1.6.5 Security and Safeguards

Spent fuel because of its potential hazard, and plutonium because of its potential use for weapons if separated from spent fuel, require measures to ensure that this material is not diverted for illegal purposes.

Unprocessed spent fuel provides its own protection against theft because of the high gamma radiation fields associated with it. A heavy shielded container (up to 100 tons weight) is required to remove spent fuel from the storage facilities. Without this shielding, those removing the fuel would receive a fatal dose of radiation. Necessary security measures to prevent theft would be taken during the shipment of spent fuel in shielded containers.

If plutonium is separated from the spent fuel, the security requirements are more demanding than for

unprocessed spent fuel. Special precautions would be taken to protect against diversion of the plutonium. For example, control over the separated plutonium would be enhanced by locating on the same site, the interim storage facility, the plant for reprocessing the fuel to recover its plutonium, and the plutonium fuel fabrication plant of the plan discussed previously. In addition, controls agreed to by the regulatory agencies, would be instituted to monitor the quantities of plutonium and its disposition amongst the various facilities. This subject would be thoroughly investigated prior to embarking on a large scale plutonium recovery and recycle program.

2.1.6.6 Transportation of Spent Fuel (9,10,11)

Small quantities of spent fuel have been shipped from the generating stations. These shipments have been few in number and have taken place at irregular intervals, however, Ontario Hydro is expecting to start regular shipment of spent fuel around 1985. This will involve shipping the spent fuel from the nuclear generating stations (approximately 1 to 2 shipments per week per station) to a central interim storage site.

Shielded shipping containers weighing tens of tons will be used to transport the spent fuel from the nuclear generating stations to the central site. These will conform to the International Atomic Energy Agency standards, and must withstand the postulated accident conditions of transport with only a very limited reduction in containment and shielding efficiency. These shipping containers must be individually approved by the regulatory authority following stringent testing and documentation.

To simulate accident conditions, such containers must continue to meet the leakage and shielding requirements after being subjected to the following cumulative tests:

1. A drop test of 9 metres unto a flat concrete pad covered by one inch steel plate.

2. A penetration drop test of 1 metre unto a 6 inch diameter by 8 inch long steel punch.

3. A thermal test equivalent to exposure to a petroleum fire at 800°C for 30 minutes.

In addition, demonstration of containment leakproofness is separately required with the vessel submerged at a depth of 15 metres of water.

Adherence to the regulatory standards and requirements should generally provide for suitable protection of the public and the environment from the potential hazards associated with the shipment of spent fuel. However further efforts are required to define in detail the shock and vibrations environment that might be imposed on shipping containers during normal and accident conditions, and to design and test such containers to confirm their ability to provide optimum operational handling and necessary protection. In addition further economic analysis is required to determine the optimum mode of transportation, either road, rail or water.

2.1.6.7 Future Work

The proposed plan for the management of large quantities of spent fuel, although based on well-established technology, requires further development of the concepts presented in the plan to assure protection of the public and the environment. Areas where further work is required include:

(a) design and development of suitable spent fuel transportation systems for large scale shipments of spent fuel,

(b) detail design and development of alternative central interim storage facilities,

(c) ongoing evaluation of the potential hazard of spent fuel materials,

(d) development and testing of packaging of high level radioactive waste in a form suitable for ultimate disposal,

(e) effects of placement of radioactive wastes for long periods of time in host rock deep underground,

(f) development of spent fuel reprocessing systems for recovery of plutonium,

(g) development of facilities for fabrication of plutonium-uranium fuel and design and development of reactors for using such fuel, and

(h) development of methods for preventing the illegal diversion of hazardous materials.

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Line Number

2.1.7 Nuclear Station Decommissioning

2.1.7.1 Discussion

The nominal lifetime of a nuclear generating station is based on financial depreciation and is taken as thirty years. It is expected that the actual useful life of the station will exceed this. However, consideration of the economics associated with maintenance and equipment replacement costs compared to station decommissioning and replacement will likely be the prime factor in establishing useful station life.

The particularly low fuelling costs of the CANDU reactor will make it an increasingly attractive means of electrical power generation in the future and may weigh heavily in favour of rehabilitating rather than decommissioning older generating stations. This rehabilitation may encompass replacing significant portions of the conventional systems of the station as well as portions of the nuclear steam supply system. If, however, the decision is made to decommission a station, preliminary investigations in Canada and abroad indicate that there are generally three states to which a nuclear station may be decommissioned (1). Each has quite different associated costs and long-term security and surveillance requirements. All three states are envisaged as involving reactor shutdown, and placement of all fuel and process system radioactive wastes in storage facilities. Decommissioning may proceed directly to any one of the three states or may be carried out sequentially over varying time periods.

The first state, "lock-up with surveillance", may be regarded as temporary and an initial step to more complete decommissioning or, depending on a number of factors, it may be sufficient for a period of thirty or forty years. With the removal of the spent fuel and radioactive wastes from process systems as well as the moderator and primary heat transport coolants approximately 98% of the radioactive materials would be removed from the station. The reactor building (containment structure) would be locked-up but auxiliary systems such as ventilation, process water, electrical, etc, which may be needed for on-going safety compliance, would be left in an operable manner. A "skeleton" staff would perform on-going surveillance, radioactivity monitoring, security, maintenance of remaining equipment, etc.

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2.1.8 Nuclear Power in Ontario

2.1.8.1 Present Status and Future Developments

For over twenty years there has been a close association between Atomic Energy of Canada Limited and Ontario Hydro directed towards development of nuclear power. There has been a general understanding that the two corporations would integrate their talents and services to provide a single non-overlapping capability from basic research to plant operation to develop the CANDU system. With the successful performance at Pickering GS, an important milestone was reached in the development of nuclear power in Canada, at a critical time of energy supply to this province. The CANDU natural uranium system provides the opportunity for Ontario to again become essentially self-sufficient in the source of energy for the generation of electricity as it once was in the days of abundant hydraulic resources. It also provides the opportunity of doing this at low cost, using the talents, experience, and manufacturing capability available in Canada.

During 1972 a major review of nuclear power in Ontario was undertaken, at the request of the Government of Ontario, by Task Force Hydro. The report containing recommendations was submitted in February 1973 (1).

Task Force Hydro agreed with the choice of CANDU reactors for nuclear power in Ontario. Of the eighteen recommendations in this report, most of which have been or are being implemented, three related specifically to the future nuclear power program of Ontario. They are:

Task Force Hydro Recommendation 3.2

Nuclear power stations be of the CANDU-PHW (Pressurized Heavy Water) type unless future studies and assessments reveal that some alternative type will more closely meet the needs of the Province of Ontario.

Task Force Hydro Recommendation 3.3

In recognition of the need to gain more operating experience and confidence with existing types of CANDU reactors and more knowledge of the economies of multiple unit manufacture, changes in design and type be resisted unless clear economic advantages can be demonstrated.

Task Force Hydro Recommendation 3.4

Ontario Hydro continue the assessment of other nuclear power reactors.

A number of events since 1972 have supported the choice of CANDU reactors as well as the choice of nuclear power over other alternatives.

At the time of the Task Force Hydro review in 1971-1973, only the first two units at Pickering had started up and were operating satisfactorily. The total station was completed ahead of schedule and for the total cost of $375 per kilowatt installed. The 15 reactor-years of operating experience at Pickering have confirmed the high performance, low-cost capability of the CANDU nuclear station.

Since 1972, the 220 MWe prototype reactor at Douglas Point has experienced a very satisfactory improvement in performance after a number of years of difficulties. It is now operating in the dual mode of supplying steam to the Bruce Heavy Water Plant A and of producing electrical energy.

Since the start-up of Pickering GS, the CANDU reactor has gained wider acceptance outside Ontario. 600 MWe CANDU nuclear units similar to Pickering are being constructed in the provinces of Quebec and New Brunswick and similar plants have been sold to Argentina and Korea.

The above events have increased Ontario Hydro's confidence in the choice of the CANDU reactor to provide the majority of electrical growth in the period up to 1995. There are a number of additional factors. The continuing association of Ontario Hydro with the federal crown agency, Atomic Energy of Canada Limited, in the conceptual development of CANDU, continues to ensure the most effective utilization of research and engineering resources available in Ontario and Canada for the achievement of mutual objectives. The CANDU technology is

entirely Canadian and yields the maximum benefit to the Canadian and Ontario economies. The manufacture and supply of materials and equipment for the CANDU reactor is almost entirely in the Canadian private sector; the nuclear industry in Canada has developed and matured to the point where it is a major and profitable factor in the Canadian manufacturing sector. The high technology associated with nuclear power creates many new opportunities for challenging work in the Canadian employment scene.

The engineering of nuclear power stations, where capital costs are high and maintenance presents particular problems, requires a strong emphasis on quality of design to obtain high reliability and performance. To meet these demanding requirements, significant changes have been made through the years in Ontario Hydro's organization and control of engineering effort, and in the development of new skills, procedures and knowledge, based on the extensive and successful experience in the design, construction and operation of the Nuclear Power Demonstration (NPD), Douglas Point, and Pickering stations, and the design and construction of the Bruce nuclear generating station.

Task Force Hydro's recommendations 3.3 and 3.4 were consistent with a program of studies initiated by Ontario Hydro in June 1971 involving a series of conceptual design studies to investigate the range of alternatives for nuclear plant to be constructed after Bruce A (2). These studies considered the engineering design, construction and financial aspects of the following: Repeat of Bruce A (4x750MW), Improved and Uprated Bruce (4x850MW), a 4x1250MW CANDU-PHW station, and an assessment of Light Water Nuclear Reactors (LWRs) for Ontario Hydro. The studies showed that there were significant engineering and operating advantages to nuclear reactor units on the same site. This became the approved plan for the Pickering B and the Bruce B generating stations.

The studies also showed that the pressure tube design of the CANDU has inherent potential for scale-up and that a greater emphasis should be placed on standardizing systems and components in the nuclear reactor to simplify design and to achieve higher reliability by utilizing proven components.

Pre-engineering and development work is therefore now proceeding in Ontario Hydro and AECL on systems and

components applicable to two standard designs of CANDU-PHW for future Ontario Hydro nuclear generating stations. These are four-unit stations using 850MW and 1250MW generating units. The two designs are very similar and many of the major components are identical. Preliminary work is proceeding on these two unit sizes to provide information on which to base decisions on the most economic unit size for the Hydro system and to provide alternatives for different locations in the province.

It has always been a requirement to undertake conceptual design studies prior to commitment of new generating plants. However, for high capital cost nuclear stations, Ontario Hydro is now involved in significant efforts of pre-engineering and development to more accurately predict construction schedules, capital and operating costs, plant performance, and to deal effectively with difficult and time-consuming engineering and safety analysis prior to commitment for construction. This practice is based on the premise that if the preparation of major specifications and the pre-engineering of a nuclear plant is thoroughly undertaken prior to commitment to a fixed schedule, there is greater assurance of an orderly design process with fewer changes and of meeting the performance and cost targets. A similar practice has been adopted by major utilities in the USA and UK.

Pickering performance, the engineering of the Bruce station, and the above studies have led Ontario Hydro to believe that, provided adequate capital can be made available, the CANDU nuclear system is the best choice for the future energy requirements of the province. The growing experience and resources of Ontario Hydro, AECL, and the Canadian nuclear industry can best be utilized for the benefit of the economy of Ontario by the continued development of the CANDU reactor system.

Assessment of the application of the US-designated light water reactor in Ontario did not show any economic advantage and some technical and logistic difficulties in comparison to the CANDU for base-load energy production. Since the completion of this assessment, which used data available in 1972, several situations have developed which reinforce these conclusions.

The US light water reactors, operating on an enriched uranium once-through fuel cycle, use about twice as

much mined uranium per unit of electrical production as the CANDU reactor system on a natural uranium once-through fuel cycle, primarily because of the poorer neutron economy of the LWR. In the past year, a significant shortage of uranium for forward delivery in the 1980's has appeared, which has substantially increased the US domestic price for uranium (3). Also, most of the western world's enrichment is supplied by plants of the United States Atomic Energy Commission and the demand for uranium-235 enrichment throughout the world is predicted to exceed supply in the 1980's (4). European and Japanese governments are anxious to become at least partially independent of this US monopoly and are making very large investments to develop alternative facilities. Thirdly, the cost of enrichment production, which is energy-intensive, has escalated substantially (5).

An additional consideration is the reprocessing of spent fuel. Because the LWR is an inefficient user of mined uranium, there is great pressure to develop the capability to recycle the plutonium produced during operation of the reactor and which is present in the spent fuel when it is removed and stored. The United States plutonium recycling program has run into difficulty and has not proceeded as expected. However, the apparent domestic shortage of mined uranium which would result if recycling was not introduced into the US nuclear program, and the consequential economic penalties of storing and not obtaining the plutonium dollar credit in the spent fuel makes the success of this program very important to the U.S. utility industry. It should be pointed out that a plutonium-uranium fuel cycle in US reactors still only brings the LWR net fuel consumption down to the level of the present CANDU using a natural once-through fuel cycle. This is one of the factors behind the US and European efforts to develop the liquid metal fast breeder reactor with its very efficient fuel consumption.

A unique feature of the CANDU system is that it can be developed in an evolutionary way to accommodate new fuel cycles as the economic situation dictates. Conceptual studies by Atomic Energy of Canada Limited include a plutonium recycle with uranium, plutonium recycle with thorium, and a thorium self-sufficient cycle (6). These fuel cycles could be introduced into the present CANDU reactors without having to modify them significantly. Successful implementation of such recycles will result in significant

improvements in efficiency of fuel consumption and will increase the utilization of nuclear fuel resources in CANDU reactors. This approach seems to be the best prospect for ensuring continuation of low cost and secure energy for the people of Ontario. The current uncertainties of long term uranium supplies and future discoveries can be offset by a vigorous development program of plutonium and thorium utilization backed up by world development of fast breeders and fusion reactors to ensure that adequate energy will always be available. Significant utilization of these advanced fuels and technologies is not expected to take place until 1995 or later.

At the time of the Task Force Hydro study in 1971-1973, the very rapid price increases in fossil fuels, which were triggered by the OPEC cartel, had not yet occurred. Since then the difference in cost between fossil fuels and uranium has experienced significant increases. These increases, which appear to be ongoing, reinforce the economic advantage of nuclear power.

2.1.8.2 Relative Economics

The relative economics of coal-fired and CANDU generation can be illustrated by comparing values for Lambton GS and Pickering GS "A", which are coal-fired and CANDU respectively. Such a comparison is meaningful because the stations are of comparable size and of similar age. Lambton GS actually went into service in 1969, about two years before Pickering GS "A". This comparison, obtained from Reference 7, is a maturity cost estimate based on actual cost experience.

The comparison assumes 80% capacity factor for each station, which is appropriate for base-loaded generating plant. Lambton GS is assumed to be burning coal from the United States. The depreciation condition for both stations is a 30 year life with an 8% capital interest rate, and the values are expressed in 1975 dollars.

Coal-Fired and CANDU Cost Comparison

Cost Component	Pickering GS "A" m$/kWh	Lambton (1) m$/kWh	Lambton (2) m$/kWh
Capital	4.60	1.70	1.70
O. & M.	1.10	0.96	0.96
Fuelling	0.98	10.60	13.52
D_2O Upkeep	0.35	-	-
Total	7.03	13.26	16.18

Note: Lambton fuel cost was escalating rapidly at the time the comparison was made. (Early 1975). The value for Lambton (1) was based on the cost of the then existing coal stock. The value for Lambton (2) was based on the then present cost of new coal supplies.

The above comparison cannot be used to justify either coal or nuclear for all future thermal generation on the Ontario Hydro grid. A detailed analysis of all factors which may change the relative economics of the two systems must be made. The following would all have a bearing on the economic relationship between coal-fired and CANDU generation:

(i) The effects of inflation.

(ii) The choice of unit in-service dates.

(iii) The choice of unit sizes.

(iv) Predicted forced outage rates and capacity factors.

(v) The method of funding and the appropriate interest rates.

(a) Capital Costs

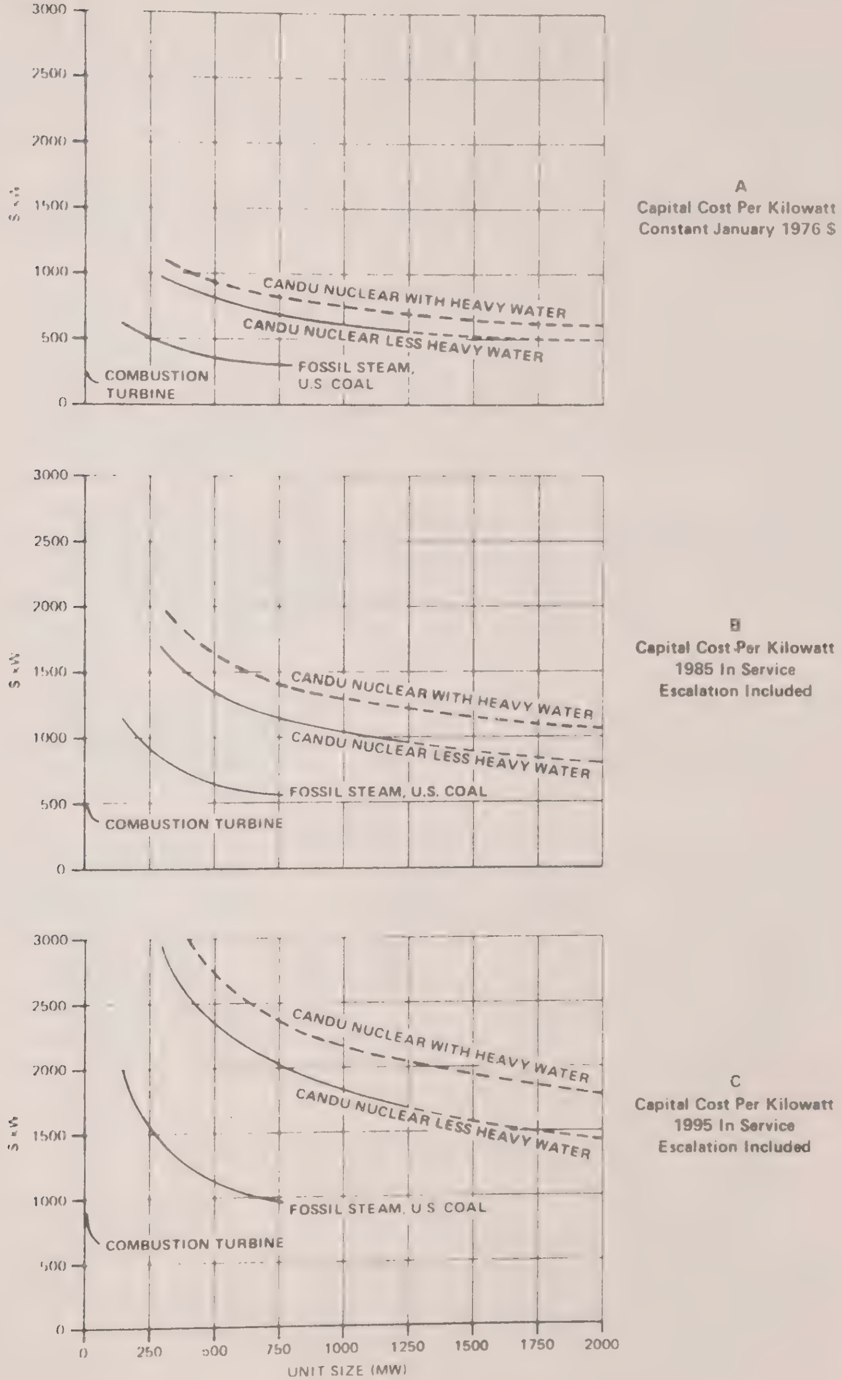
The effects of inflation, in-service dates and unit sizes on the capital costs of nuclear and fossil fuelled units are shown on Figure 2.1.8-1 for the types of thermal generation which are considered as feasible new sources for Ontario up to 1995. These are:

- CANDU nuclear

- Fossil-steam, coal-fuelled

Figure 2.1.8–1

Thermal Generation, Estimated Capital Cost Per Kilowatt Sent–Out from the Generating Station (4–Unit Plants)



Estimated capital costs include net cost of commissioning and for nuclear units include cost of half initial fuel

- Gas turbines, also known as combustion turbine units (CTU)

Capital cost is defined as all the costs for material, equipment and labour to construct a project plus interest on funds spent on this work up to the actual in-service date.

The figure shows the estimated capital costs including the net cost of commissioning, on three bases:

- No escalation, all costs equal to 1976 costs.

- Escalation included, for stations with their first units coming into service in 1985.

- Escalation included, for stations with their first units coming into service in 1995.

The figure shows that the capital cost per kilowatt of nuclear units is substantially greater than that of fossil-steam units of the same size; and the capital cost per kilowatt of the latter is substantially greater than that of combustion turbines.

The relativity of the total estimated capital costs per kilowatt is almost unchanged by escalation, but the dollar differences between alternatives do escalate.

The figure also indicates the economy of scale, i.e., the manner in which costs per kilowatt decrease as the size of units is increased. The advantages of economy of scale progressively decrease as unit sizes are increased. It persists for larger unit sizes of nuclear units than of fossil units. Extrapolation of the figures indicates that the economy of scale will eventually disappear for nuclear units of some size greater than 2000 MW, and for fossil units greater than 1500 MW.

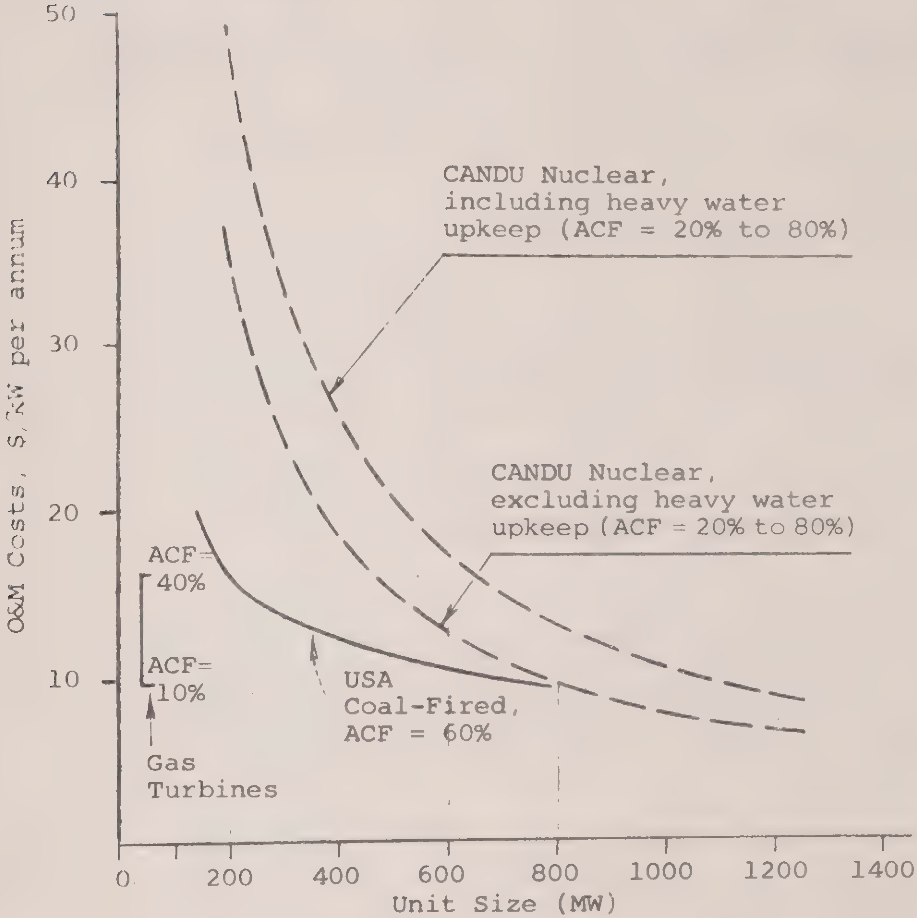
(b) Operation and Maintenance Expenses

Figure 2.1.8-2 shows the estimated normal annual operating and maintenance expenses per kilowatt, excluding fuel, for 1976. It indicates the economy of scale: larger units have lower costs per kilowatt. Costs for nuclear units are somewhat higher than those of fossil-steam units of similar size. This is

Figure 2.1.8–2

Thermal Generation, Estimated Annual Operations & Maintenance Costs in Dollars Per Kilowatt Sent-Out at the Generating Station

These data apply for 4-unit generating stations and do not include the cost of fuel consumed in the stations.



in part due to the cost of upgrading and replacing heavy water in the nuclear units.

(c) Energy Production Expenses

These are the costs of the primary fuel consumed per kilowatthour of electricity generated. For 1975 conditions, they are estimated at:

$1.27 per MWh, for CANDU nuclear units, 500 MW and larger

$10.26 per MWh, for USA coal-steam units, 500 MW and larger

$25.20 per MWh, for combustion turbine units

It is estimated that these costs will continue to escalate in the future, and account of this is taken in the remainder of this section.

(d) Total Cost Comparison

The total cost comparisons encompass all the above costs.

For the nuclear units, the cost of the fuel consists of two components: half the initial charge of the reactor which is included in the capital cost and the estimated equilibrium annual burnup of fuel. The total cost comparisons for thermal generating units are given in Figure 2.1.8-3 on the basis of total cost per kilowatt hour sent out.

(e) Economic Summary

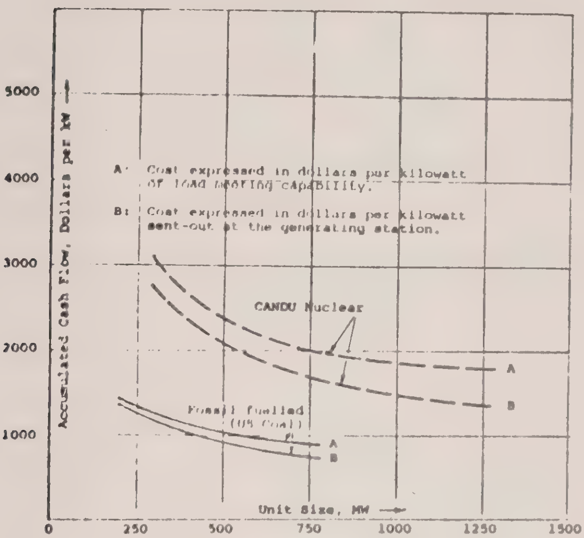
Nuclear stations have a high capital cost and low fuelling cost. Once they are built a commitment has been made to a high carrying charge which will be incurred whether or not the station is operated. Hence once the station is built it is highly desirable that it operate at high capacity factors. Nuclear stations therefore meet the electrical load which persists throughout the day.

A coal-fired station has a significantly lower capital cost and the carrying charges are correspondingly less. The fuel cost is, however, about ten times that of a nuclear station. There is less incentive to operate coal-fired stations at high capacity factors and they are suitable for meeting the intermediate load that persists throughout the

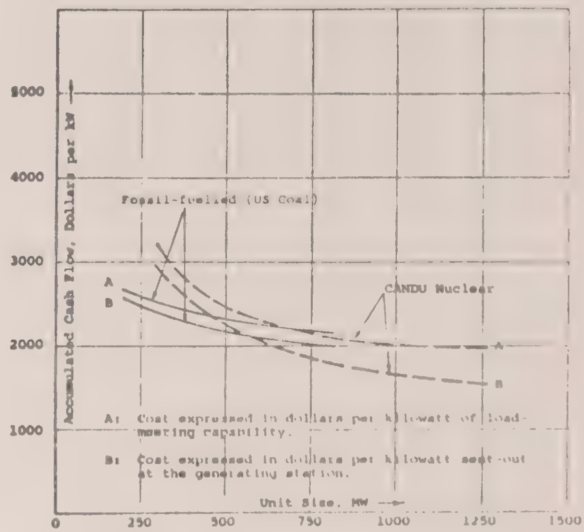
Figure 2.1.8–3

Thermal Generation, Accumulated Cash Outflows at Year 30
For 4-Unit Stations Coming Into Service in 1985,
Discounted to 1985

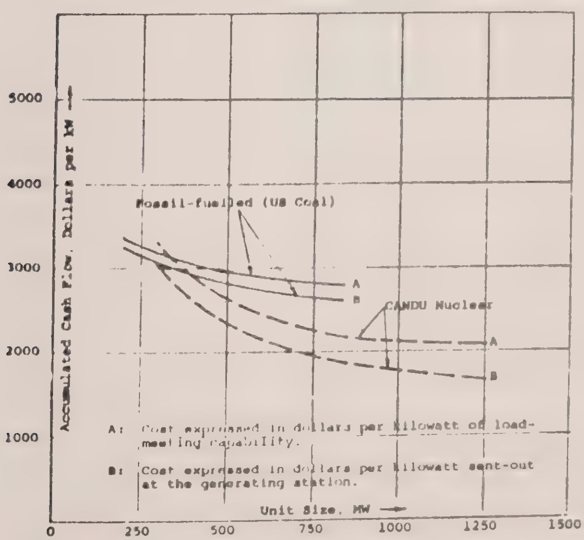
I. Excluding Cost of Fuel



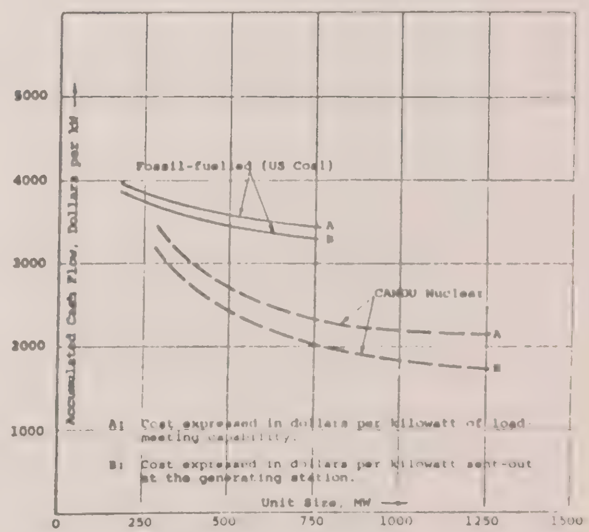
II. Including Cost of Fuel
Annual Capacity Factor: 40%



III. Including Cost of Fuel
Annual Capacity Factor: 60%



IV. Including Cost of Fuel
Annual Capacity Factor: 80%



Notes:
1. Discount factor 10% per annum.
2. LOLP Index 1/2400.
3. AFORs = 100% of Forecast.

working day and evening periods. At night the coal stations can economically reduce output to correspond to the declining electrical demand.

Parameters which favour nuclear, rather than fossil generation, are those which minimize the effect of the high capital cost of the nuclear station. Hence increasing the capacity factor spreads the capital carrying charges over a larger energy production and reduces the effect on the total unit energy cost. Increasing the interest rate increases the carrying charges and favours the lower capital cost fossil option.

The data presented here can only be used as a general indication of the relative economics. In practice, more elaborate studies are done, to include such effects as:

(a) Various rates of load growth.

(b) Economics associated with providing operating reserves whose magnitude is increased as unit size is increased.

(c) Economics associated with bulk transmission and interconnection requirements, which may increase as unit size is increased.

(d) Scheduling planned maintenance.

(e) The matching of units to the year-by-year growth.

(f) Different nuclear energy-production capability of programs with different sizes of nuclear units.

(g) More accurate estimates of the costs and reliability of alternatives.

(h) The higher outage rates of generating units during their period of immaturity.

(i) Estimates of the capability of manufacturers to provide equipment for larger sizes of units, etc.

The evaluation of the total system cost of energy and capacity from alternative types and sizes of generating units is scheduled for the RCEPP information hearing on Generation Planning, July 7 and 8, 1976.

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6. Atomic Energy of Canada Limited, "The Canadian Nuclear Power Program", Report No. AECL-4767, April, 1974.

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2.2 GENERATION, FOSSIL AND OTHER TYPES

2.2.1 Principal Generating Station Types and Modes of Operation

2.2.1.1 Hydro-Electric

A Hydroelectric station uses the energy that water provides when falling from one elevation to a lower elevation. The water is directed against the blades of a hydraulic turbine and rotates the turbine shaft. This in turn rotates an electric generator and produces electric energy.

The maximum amount of energy that can be generated at any potential hydroelectric site is limited by the quantity of the available water supply and the difference in elevation, called the "head", through which the water can be made to fall. These factors are determined by the natural features of the site: the pattern of rainfall and runoff, the topography, and the geology of the area.

In the process of studying the development of a new site, account is taken of such factors as the extent to which dams and other works can increase the usable head, the extent to which water can be diverted from neighbouring watersheds, the feasibility of developing water reservoirs to permit water to be used in a different (or regulated) pattern than the natural pattern of inflow, and the economic and operating advantages of alternative total amounts of installed generating capacity.

In a state of nature, the pattern of runoff tends to be highly variable from one season to another and one year to another. It may be possible to develop sufficient water reservoir capacities to regulate all the water flowing into the generating station to correspond to the required pattern of electric demand. However, such complete regulation has not been possible in Ontario.

When studying a new site, one considers the cost of successively increasing the installed generating capacity and compares it with the successive increments in peak power and energy output that could be generated. At low installed capacities, the water supply may be adequate to operate the generation continuously, i.e., at base load. Generally speaking, as the capacity is further increased, the total installation cannot operate

solely in the base load mode; some must operate at intermediate load, and some at peak load. With a sufficiently large installation and development of adequate reservoir capacity, it may be appropriate to use all the water for intermediate load, or all the water for peak load.

Most of the hydroelectric generating potential in the province of Ontario has already been developed.

Figure 2.2.1.1-1 outlines estimates of the larger remaining hydroelectric generating potentials. Nearly all of the remaining potentials are on the Northern Ontario river systems. Therefore the cost of electric transmission needed to incorporate their output into the Ontario Hydro bulk power transmission system is a significant factor in their economic assessment. Of the potentials listed, only the development of the Albany River sites would provide a major source of energy. Few of the other potentials can provide energy greater than 50 average MW; and most of these are expected to be economic only if new electric load appears close to them, or if they are developed for the peak load mode of operation.

It should be noted that water from portions of the Albany River drainage basin has already been diverted for a number of years to increase the flow to generating stations on other river systems. Thus, the Ogoki diversion now directs flow from the Albany River into the Lake Nipigon whence it flows into the Great Lakes and St. Lawrence River. The Lake St. Joseph diversion now directs flow from the Albany River into the English River, whence it flows into the Winnipeg River and ultimately into the Nelson River. Figure 2.2.1.1-1 is arranged to show the potentials which are unaffected by these diversions and changes to them, and the potentials which are affected.

The development of the Albany River to its estimated generating capacity of about 3200 MW requires the construction of a large number of power dams and a significant number of additional control structures to divert water into the Albany River from the Whiteclay, Winisk, and Attawapiskat Rivers. It also requires discontinuing or drastically reducing the present diversion of the Ogoki and the Lake St. Joseph out of the Albany watershed. If it is undertaken, it would adversely affect the existing and possible future developments on the English,

Figure 2.2.1.1-1

Estimate of Ontario's Remaining Conventional Hydroelectric Potential, in the Larger Developments (Note 1)

River and Site	Hours of Peak Output (Note 2)	Estimated Increments in Peak Capacity in MW		Estimated Increments in Average Annual Energy, in Average MW	Capacity Factor of Increment, % (Note 3)
		Installed	Dependable		
A. NEW SITES UNAFFECTED BY ALBANY RIVER DIVERSIONS					
ABITIBI					
Long Sault Rapids	2	80	69	27	39
Nine Mile Rapids	-4 (Note 4)	128	121	66	54
	-2 (Note 4)	256	243	71	29
MATTAGAMI					
Grand Rapids	-4 (Note 5)	109	102	62	61
	-2 (Note 5)	218	190	77	41
MADAWASKA					
Highland Falls	2	95	91	16	18
MISSINAIBI					
Thunderhouse Falls	-7	13	13	10	77
	-2	42	42	20	48
Long Rapids	-7	31	31	25	81
	-2	100	100	49	49
MISSISSAGI					
Gros Cap	2	262	258	47	18
MOOSE					
Grey Goose	2	188	175	74	42
Renison	2	188	186	76	41
WHITE					
Chigamiwingum	8	16	15	14	93
Umbata	8	14	14	12	86
Chicagouse	8	11	11	10	91
B. NEW SITES AFFECTED BY ALBANY DIVERSIONS POTENTIAL ASSUMING CONTINUATION OF EXISTING ALBANY DIVERSIONS					
ENGLISH					
Maynard Falls	8	51	46	27	59
LITTLE JACKFISH					
Mileage 12.5	8	38	36	26	72
Mileage 7.5	8	46	46	33	72
C. NEW SITES AFFECTED BY ALBANY DIVERSIONS POTENTIAL ASSUMING TERMINATION OF EXISTING ALBANY DIVERSIONS (to English and Nipigon Rivers)					
ENGLISH					
Maynard Falls	N/A				
LITTLE JACKFISH					
Mileage 12.5	N/A				
Mileage 7.5	N/A				
ALBANY					
Achapi	4	131	131	33	25
Eskakwa	4	268	166	119	72
Miminiska	4	57	57	35	61
Frenchman	4	95	95	61	64
Washi	4	73	73	47	64
Kagiami	4	117	117	83	71
Martin	4	70	70	51	73
Nottik	4	73	73	55	75
Buffaloskin	4	101	101	83	82
Wabimeig	8	217	119	163	137
Chard	8	536	536	376	70
Hat	8	422	399	284	71
Blackbear	8	402	402	279	69
Biglow	8	382	382	268	70
Stooping	8	308	308	206	67
Total of Albany Developments:		3252	3029	2143	71

The above capacities presume the following diversions are made into the Albany River:
Whiteclay Diversion
Winisk-Attawapiscat Diversion

Figure 2.2.1.1-1

River and Site	Hours of Peak Output (Note 2)	Estimated Increments in Peak Capacity in MW: Installed	Dependable	Estimated Increments in Average Annual Energy, in Average MW	Capacity Factor of Increment, % (Note 3)
D. EXTENSIONS OR REDEVELOPMENT OF EXISTING STATIONS					
Schemes Unaffected by Albany Diversions					
ABITIBI					
Canyon	2	790	714	20	3
Otter Rapids	2	175	161	4	2
MATTAGAMI					
Little Long	2	122	106	17	16
Harmon	2	136	107	18	17
Kipling	2	136	118	19	16
Smoky Falls	-4 (Note 6)	102	100	43	43
	-2 (Note 6)	157	239	66	28
MISSISSAGI					
Red Rock Falls	2-3	36	33	2	6
OTTAWA					
Otto Holden	2-3	202	156	6	4
Des Joachims	2	696	640	19	3
MONTREAL					
Hound Chute/Ragged Chute Redevelopment	2	98	98	19	19
E. EXTENSIONS OR REDEVELOPMENT OF EXISTING STATIONS					
Schemes Affected by Albany Diversions Potential Assuming Continuation of Existing Diversions (to English and Nipigon Rivers)					
ENGLISH					
Ear Falls	8	7	5	4	8
NIAGARA					
SAB #2 (Existing Tunnels)	1/2	305	199	0	0
SAB #3 (New Tunnel)	1	458	501	138	28
NIPIGON					
Pine Portage Ext	8	27	22	1	5
Cameron Falls Ext	8	18	17	2	12
Alexander Ext	8	19	13	2	15
Schemes Affected by Albany Diversions Potential Assuming Termination of Existing Diversions (to English and Nipigon Rivers)					
ENGLISH					
Ear Falls	N/A				
NIPIGON					
Pine Portage Ext	N/A				
Cameron Falls Ext	N/A				
Alexander Ext	N/A				
NIAGARA					
SAB #2 (Existing Tunnels)	1/2	305	199	0	0
SAB #3 (New Tunnel)	1	458	501	138	28

Note 1: The table includes new sites capable of producing 10 or more average MW. It does not include potential sites on the Severn, Winisk, and Attawapiskat Rivers because little data are available on them.

Note 2: These are the hours of operation at the dependable peak capacity that the site can provide under extremely low water supply conditions.

Note 3: The Capacity Factor corresponds to the Increment in Average Annual Energy and the Increment in Dependable Peak Capacity.

Note 4: The 4-hour peak applies if Nine Mile Rapids is developed in step with the existing generating station at Otter Rapids.
The 2-hour peak applies if Otter Rapids is extended to provide 2-hour peaking, and Nine Mile Rapids is developed in step with it.

Note 5: The 4-hour peak applies if Grand Rapids is developed in step with the existing generating stations at Little Long, Harmon, and Kipling.
The 2-hour peak applies if Little Long, Harmon, and Kipling are extended to provide 2-hour peaking, and Grand Rapids is developed in step with them.

Note 6: The 4-hour peak applies if the existing generating station at Smoky Falls is redeveloped in step with the existing generating station at Little Long.
The 2-hour peak applies if Little Long is extended to provide 2-hour peaking, and

Table 2.2.1.4-1 - Combined Cycle Plants in Operation (or Partial Operation) in the US

Utility	Total Generating Capacity	Gas Turbine Generating Capacity	No. of GTs	Operating Hours GTs	Avg Plant Heat Rate BTU/kw	Fuel Type	Mfgr	In-Service Date
1. Duquesne Light Co, Brunot Island Pa.	331	189	3	1229	14372	#2 oil	G.E. STAG300	GT-1973 ST-1974
2. Jersey Central Power & Light Co Gilbert GS	330	190	4	3000	12600	#2 oil	G.E. STAG300	GT-1974 ST-Expect Mar 1977
3. Public Service Co of Oklahoma Comanche GS	260	140	2		9250	Gas	Westing-house PACE260	GT-1973 ST-1975
4. Public Service Electric and Gas Co., Burlington GS	128	88	2				TP&M FT4-All	GT-Spring 1972 ST-Summer 1974
	1049	607	11					

Table 2.2.1.4-2 - Combined-Cycle Plant Additions In the U.S. Based On Scheduled Dates of Commercial Operation as of July 1, 1974

	Utility	Installed Gen. Capacity		No. of	Nameplate Rating	Mgfr &	Scheduled In-Service
		Gas Turbine	Plant	GT	GT	Model	Date
1.	Arizona Public Service Co., West Phoenix, Arizona	174 MW	255 MW	3	58	GE STAG100	1976
2.	Duke Power Co. Spencer, N.C.	93	128	3	31	TP&M TP4-2	
3.	Florida Power & Light Co., Palatka, Florida	275	500	4	68.8	Westinghouse W501B	1975
4.	Houston Lighting and Power Co T.H. Wharton	205.2	318.2	4	51.3	GE PG7661	-
	Houston, Texas	216.0	329.0	4	51.3	GE PG7661	-
5.	Louisianna Power and Light Co. Sterlington, La	133.2	234.5	2	66.6	GE7000	-
6.	Oklahoma Gas and Electric Horseshoe Lake Harrah, Oklahoma	27.0	245	1	27.0	GE Frame 8	-
7.	Salt River Project Santan #1,2,3,4 Gilbert, Arizona	241	289	4	60.3	GE STAG 100	1975

Utility	Installed Gen. Capacity: Gas Turbine	Installed Gen. Capacity: Plant	No. of GT	Nameplate Rating GT	Mgfr & Model	Scheduled In-Service Date
8. Southwestern Public Service Co. Borger, Texas	25.0	257	1	25	Westinghouse W-251	-
9. Braintree, Mass. Potter GC No. 2	66.23	-	1	66.28	-	1976
10. Touton, Mass. Cleary No. 9	20	-	1	20	-	1974
11. Floridan Power & Light Company Palatka 3,4	276	-	4	68.8	Westinghouse W501B	1975
12. El Paso Electric Co	62.5	-	1	62.5	-	1975
Newman No. 4A, 4B	62.5	-	1	62.5	-	1975
13. Houston Lighting & Power Co Greens Bayou 1,2,3,4,5,6	360	-	6	60	-	1976
14. San Diego Gas & 1A,1B,1C,1D	296	-	4	74	-	1979
15. Southern California Edison						
Cool Water No. 3A 3B	138	-	2	69	-	1977
Cool Water No. 4A 4B	138	-	2	69	-	1978

Little Jackfish, Nipigon, Niagara, and St. Lawrence Rivers; and the Winnipeg and Nelson Rivers in Manitoba.

As shown on Figure 2.2.1.1-1, the energy potential from the Albany scheme is estimated at 2143 average megawatts. Subtracting the loss from existing developments that would occur as a result of the Albany diversions, the net energy potential is about 2000 average MW. This can be compared with the total hydraulic energy generated in 1975 of 4000 average MW.

In addition to the Albany, the total of all other undeveloped energy in the province at sites larger than 10 MW is 1200 average MW. This does not include the Severn River which empties into Hudson's Bay near the Manitoba border and which may have a potential of about 600 average MW.

There are also large numbers of small sites throughout the province, many of which have been developed for mechanical power and have been removed from service because of changing technology and high operating and maintenance costs.

2.2.1.2 Steam

(a) Steam Cycle

The two main types of steam generating plants for electrical generation are fossil and nuclear.

The operation of both the fossil-steam and nuclear-steam generating systems is described separately in sections 1.2(b) and 1.2(c) respectively. There are some similarities in these systems, particularly the steam turbine cycle, some of the important features of which are discussed below.

The Steam Turbine Cycle

In the steam cycle, water enters a boiler where it is heated to produce steam. The steam is expanded in a turbine where its heat is converted to shaft power which, in turn, is converted to electricity in a generator. The steam exhausting from the turbine is condensed to water in a condenser and this water is then pumped to the boiler to complete the cycle.

The steam turbine cycle has been developed to a high degree of sophistication, the levels of efficiency being limited only by the laws of thermodynamics and the capacity of available materials to withstand the higher steam temperature and pressure.

The efficiency of the steam turbine cycle is dependent upon a number of factors, particularly:

i) The difference in the temperature and pressure of the steam entering and exhausting from the turbine.

ii) The number of times that the steam is removed from the turbine to be reheated in the boiler prior to completion of expansion in the turbine.

iii) The number of stages at which water is heated enroute to the boiler, by partially spent steam from the turbine.

Each of these points is discussed below:

i) <u>Steam Temperature and Pressure</u>

The greater the difference between the inlet and exhaust steam temperature, the more efficient the steam cycle. The exhaust conditions are determined by the temperature of available cooling water, and this is fixed for a given site. Thus the only way to increase the difference is to raise the temperature and pressure of the inlet steam.

The inlet steam to a steam turbine can be classified in the following terms:

- sub-critical wet steam

A boiler operating at "sub-critical pressures" is similar to a kitchen kettle, although it operates at much higher temperatures and pressures. The boiler drum contains water from which steam vapourizes at a temperature of about 500°F. This "saturated" steam is piped directly to the turbine in which it expands to rotate the bladed wheels. As

the steam starts to expand it cools, causing water droplets to form and a turbine supplied with saturated steam is referred to as a "wet-steam turbine". Ontario Hydro's Candu stations have wet-steam turbines.

- sub-critical dry steam

If the saturated steam leaving the boiler drum is passed through an array of tubes and heated, its temperature is raised. Due to tube material limitations the upper limit of this temperature is generally 1000°F and the boiler must be operated in a way that the steam temperature does not exceed this value by more than a few degrees. Otherwise equipment life can be shortened dramatically. This situation can be appreciated by noting that steam pipes carrying steam at 1000°F are literally red hot. This high temperature steam can be expanded through most of the turbine before it is cooled sufficiently to produce water droplets. Hence such turbines are referred to as "dry-steam turbines". All of Hydro's fossil steam units operate with dry steam at sub-critical pressures.

- super-critical dry steam

On raising the pressure above 3200 psi, the density of steam and water becomes identical. The water/steam interface disappears and the water is converted to steam without any apparent change in its state and this eliminates the need for a steam drum with its accompanying cost and operating constraints. Super-critical dry steam at 1000°F temperature performs in much the same way in the turbine as sub-critical dry steam.

There are major gains in both cycle efficiency and turbine costs by using high temperature dry steam rather than lower temperature wet steam, although no technology has yet been developed to achieve this with water cooled nuclear reactors. Marginal advantages to efficiency and boiler and turbine costs

result by using super-critical rather than sub-critical pressures. However, other factors offset these and these are discussed in section 1.2(b) following.

ii) Reheating of Steam

As noted above, steam cools as it expands through the turbine. If it is removed after partial expansion, reheated once more in the boiler to the maximum temperature, and then returned to the turbine to complete its expansion, there is a marked gain in efficiency. A second reheating process provides a small additional gain. Ontario Hydro uses single stage reheating of this type in its fossil-steam units. It has been unable to justify a second stage because of resultant increased capital costs and reduced reliability.

Reheating has the added advantage of reducing potential detrimental effects of moisture on the exhaust portion of a turbine. For this reason reheating is used with nuclear wet-steam turbines, even though the efficiency gains in this case are less significant.

iii) Regenerative Boiler Feedwater Heating

The water condensed from turbine exhaust steam has a temperature of $80^{\circ}F$ as it leaves the condenser. If this water is fed directly into a boiler, a large amount of heat is required to raise temperature of the water to the boiling point. However, by preheating the water with steam extracted from the turbine, virtually all the heat will be used to vapourize the water to steam, and/or to raise the steam temperature. The steam extracted from the turbine can be used very efficiently since it has already provided some mechanical energy and all of its latent heat can be transferred to the feedwater, rather than being discarded to cooling water. (This is the same principle as that used in combined heat and power systems for district heating.) As a result, cycle efficiency is

increased. If the steam is extracted at a number of turbine stages during expansion, further increases in efficiency are achieved.

Ontario Hydro's modern fossil units generally have 7 stages of regenerative feedwater heating. This reduces the fuel used by the boiler by about 35% but it also reduces the unit output by about 20%, since only about two-thirds of the steam is expanded through the entire turbine. The net result is an improvement in efficiency of about 15%. There is a similar improvement in the nuclear-steam cycle efficiency with 5 stages of feedwater heating.

The determination of the optimum number of feedheating stages is a balance between a number of factors, the most important being the cost of additional equipment and the value of future energy savings.

Other Aspects of the Turbine Cycle

Although efficiency is a major goal, the cycle must also be designed to protect the hardware from excessive temperature changes, moisture erosion, chemical attack, water ingestion, and other incidents during both steady state and non-uniform operation. Thus its proper design, construction and operation is basic to the reliability and maintenance cost of the unit.

(b) Fossil-steam Generation

i) Description

A fossil-fuelled generating station is a plant for converting the energy in fossil fuel to electricity. Two main requirements then are that it must have a system for receiving fuel and it must be connected to the electrical transmission system. The transformation of fossil to electrical energy is achieved by burning the fuel to produce steam used to rotate a steam turbine driving an electrical generator. The electricity from the generator terminals is fed into the

transmission system through appropriate transformers and switches.

Examining the process in somewhat more detail shows that the fuel, coal, oil or gas, is fed into the furnace of the steam boiler where it is burned is suspension (all three fuels burn in essentially the same manner.) Natural gas is brought into a generating station by a branch line from a local gas pipeline. It does not require storage of any kind on the station and in this sense is very convenient. Natural gas is very desirable as a clean fuel; that is, it produces very little ash and contains very little sulphur, but it is available in very limited quantities. Oil, usually residual oil, can be brought to the station by pipeline, boat or train and requires storage facilities, generally of an extensive nature on the station. Coal is delivered by boat or train and also requires considerable storage space and extensive handling, crushing and pulverizing facilities in order to prepare it for firing into the furnace.

The boiler or more accurately, steam generator, is essentially a huge furnace lined with tubes carrying water and steam. Water is fed into these tubes and steam is collected in a drum at the top of the furnace, further heated to a higher temperature (superheated) and let to the steam turbine through large pipes. The steam is expanded through the turbine where it gives up energy to rotate the turbine generator and is then exhausted at low pressure to a condenser. The condenser is a device for returning the steam to the liquid state so that it may be pumped back to the boiler for heating in a continuous cycle. The condenser is operated at the lowest feasible temperature in order to permit the extraction of the maximum amount of energy from the steam. The low condenser temperatures are normally achieved by using cold lake or river water for cooling.

Burning of fuel in the furnace in addition to producing the heat to raise steam as mentioned above also produces ash and hot gases. The heavier ash which is termed bottom ash falls to the bottom of the furnace and is removed by a hydraulic transport system. The lighter ash which stays suspended in the gas is termed fly ash and this is collected in large and highly efficient electrostatic precipitators. In order to release the gases to the atmosphere at a height to ensure adequate dispersion tall chimneys are used.

Figure 1 which is a simplified cross section of a coal fired generating station shows the flows of fuel (coal), flue gas cooling water and steam.

ii) <u>Development and Function</u>

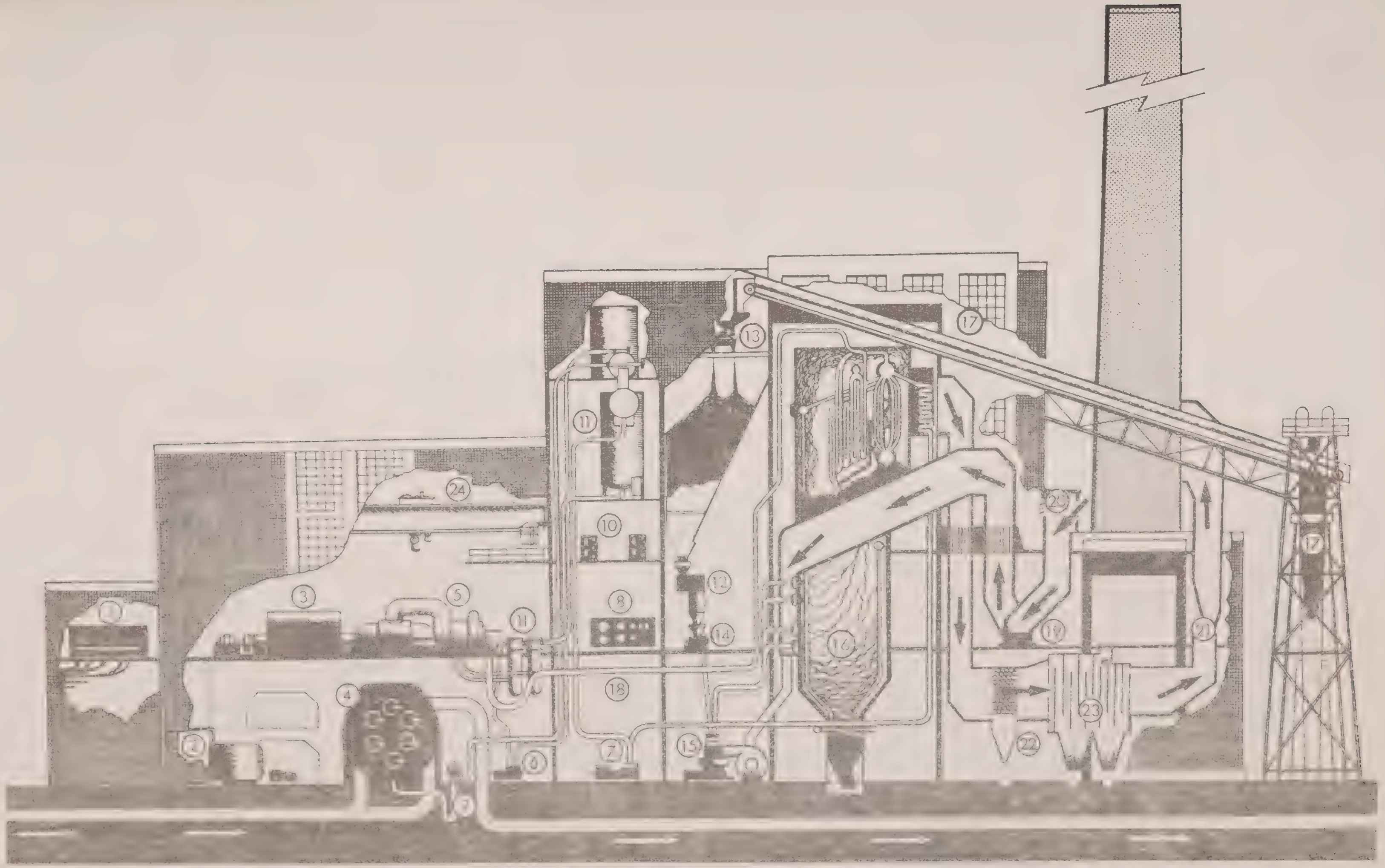
Fossil-steam power plants for electrical generation have been in operation for many years in Europe and North America. The introduction of steam generation into the Ontario Hydro system occurred in the late 1940's with first operation at R.L. Hearn in 1951. Until that time the development of the province's water resources was sufficient to meet the load growth.

Since efficiency of generation using a steam turbine is dependent chiefly on the difference between the energy in the steam admitted to the turbine and the energy remaining when it is rejected to the condenser it follows that the evolution of plant design has been to produce equipment which will permit the greatest energy extraction. The lower energy limit is set by the temperature of the water available for condenser cooling. The main effort then has been to raise the upper energy limit by increasing the inlet steam temperature and pressure. The development of steam generators and turbines has witnessed a fairly progressive increase in steam temperatures and pressures up to the 1960's. From that time and into the present it appears that a temperature barrier of about 1000°F has been reached.

Beyond this temperature present technology cannot provide materials to reliably withstand the operating stresses. Pressures have also increased, usually in steps of about 200 psig up to about 2400-2600 psig as the limit of sub-critical drum type boilers. The introduction of super critical boiler; that is, boilers producing steam at conditions above the critical steam point, permitted a slight gain in efficiency over the limit reached by sub-critical boilers. Super critical boilers were developed in both Europe and North America and several came into service in the 1960's. However, because the reliability has been somewhat less than expected and because of the ingerently greater difficulty in load following there has been a return to sub-critical boilers for most new generation in the last half dozen years. Ontario Hydro has carried out evaluations of sub-critical and super-critical cycles as applied to its system requirements and decided to stay with sub-critical cycle.

The other major trend in generating equipment design has been a steady increase in unit rating. This also appears to have reached a temporary limit at least, in the last few years. There appears to be only very marginal economic gains in increasing sizes beyond the present maximum. At present, single line (tandem compound) 3600 rpm fossil steam turbines operating at sub-critical steam pressures, have paused at an upper limit of about 900 MW. Super critical turbines seem to have reached a similar plateau at 1300 MW.

Increasing the turbine ratings has produced a reduction in the cost per kilowatt as a result of the realization of economies of scale. This now seems to be approaching a limit. Large turbines because of their proportionally greater metal masses are susceptible to greater thermal stresses induced by temperature differentials in the shells and rotors. For this reason they require a longer start-up period and are less suitable for



1. CONTROL ROOM
2. STATION SERVICE TRANSFORMER
3. ELECTRIC GENERATOR
4. CONDENSER
5. TURBINE
6. BOOSTER PUMP
7. FEED PUMP
8. STEAM GENERATOR CONTROL
9. CONDENSATE PUMP
10. STATION SERVICE SWITCHBOARD
11. HEATERS
12. COAL FEEDER
13. TRIPPER
14. SCALES
15. PULVERIZER
16. STEAM-GENERATOR
17. COAL CONVEYOR
18. STEAM LINE
19. FORCED DRAFT FAN
20. AIR INTAKE
21. INDUCED DRAFT FAN
22. MECHANICAL DUST COLLECTOR
23. ELECTROSTATIC PRECIPITATOR
24. CRANE

FIGURE 2.2.1.2 – 1 HOW A STEAM GENERATING STATION WORKS

load following then smaller units. Ontario Hydro has not progressed beyond unit sizes of 500 MW to date, although 750 MW units may be appropriate for future plants.

Fossil fuelled steam generating stations were first introduced into the Ontario Hydro system primarily for the purpose of meeting peak loads, as the lower cost hydraulic generated power could provide most of the base load requirements in the early years. As the load has grown, more fossil steam stations have been added and the percentage of base load carried by them has necessarily increased but meeting peaks is still an essential role for fossil generation. The introduction of nuclear generation with its lower operating costs has limited the projection of fossil fuelled stations for base load operation and the addition of future fossil fired stations to the system will be primarily to meet peaking requirements.

With the exception of Lennox GS which was designed to burn residual oil and is currently undergoing commissioning, the stations presently operating in the system were designed to burn bituminous coal from the Appalachian region of the U.S. The quantity of U.S. coal burned last year was about 7.5 million tons. The R.L. Hearn plant originally designed for this coal has undergone a conversion in order to burn natural gas as well as coal. This was done as a means of reducing the SO_2 emissions from this Metro area station. An addition of two units totalling 300 MW being added to the existing one 100 MW unit at Thunder Bay in the West System, are designed to burn Saskatchewan lignite as a primary fuel with the capability of burning sub-bituminous and bituminous coals from Western Canada if necessary.

It is planned to meet future increases in coal requirements in the East System with bituminous coal from Western Canada. This coal movement is expected to start in 1978 and reach about four (4) million tons by 1980. The western coal is quite low in

sulphur and will therefore reduce SO_2 concentrations in the flue gas below those produced by medium sulphur U.S. coal. It is planned to blend the Western Canadian coal with the U.S. coal to produce a sulphur level which will more than meet SO_2 air quality regulations. Since some sulphur is required in the boiler gas to precipitate the fly ash, there are potential problems associated with collecting fly ash from low sulphur Western coal. The blending of U.S. and Western coal shows promise of resolving this problem.

The successful development of flue gas desulphurization systems for the purpose of removing SO_2 from flue gas would permit the burning of more high sulphur coal while still meeting the air quality regulations. The development of these systems has, however, been disappointingly slow and the cost estimates have increased at a very great rate. In short, it appears that reliable systems will not be available earlier than the 1980's and the cost will be very high. The blending of low sulphur Western Canadian coal with medium sulphur U.S. coal therefore appears to be a very positive and reasonable approach to lowering SO_2 emissions.

The use of natural gas as a fuel for new generating stations appears most unlikely. The situation with respect to oil is less clear but it seems unlikely that oil will be planned as a fuel in Ontario Hydro's system beyond Wesleyville GS.

2.2.1.3 Gas Turbines

In a gas turbine cycle, air is compressed, fuel is added, the mixture of air and fuel is ignited, and the resulting high temperature mixture of air and combustion products is expanded directly through the blades of a turbine, causing them to rotate and drive a generator to produce electrical power. When the gas has been expanded to atmospheric pressure, it can do no further work and the heat remaining in the gas can either be discarded to atmosphere in the high temperature stack gases, transferred to the incoming air/fuel mixture to preheat it, or

transferred to a steam boiler to produce steam for a conventional steam cycle.

Because of basic process requirements, the gas turbines are able to operate at higher temperatures than steam turbines and therefore have potential for higher efficiencies. A simple cycle has an efficiency of about 27%, while a heat recovery cycle has an efficiency of 33%. Combined gas turbine and steam turbine cycles (paragraph G) are a more recent development and their efficiencies are claimed to be in excess of those of the large fossil-steam generating units.

Because the moving parts of a gas turbine are exposed directly to the combustion products, a fuel with very little corrosive impurities (such as sulphur, vanadium, sodium, etc.) must be used. In practice either distillate oil or natural gas are used. Residual oil may be used if clean-up systems, currently being developed, become available. Firing of coal directly in a gas turbine is impractical because of the erosive effect of coal ash and the corrosive effect of sulphur compounds on turbine blading. The necessity of using scarce, high cost fuels is a serious drawback to gas turbines. In the longer term, the development of coal gasifiers or fluidized bed combustors may enable the use of coal derived fuels in gas turbines thus overcoming present fuel limitations.

The start-up time requirement for gas turbines is much less than for a steam turbine. Aircraft type gas turbines are capable of carrying full load in less than five minutes and industrial type are capable of meeting full load in 15 to 30 minutes. Such rapid starts are not recommended however unless absolutely necessary. The starting time of steam turbines varies with size and the length of time that it has been shutdown but it varies between 2 hours and 5 hours.

The lifetime and reliability of gas turbines are poorer than that of steam turbines and the maintenance costs are higher. However, in some utilities the low capital cost and rapid start capability of these units may make them attractive for peak load or reserve duty where they can supply power during short periods.

The purchase of additional gas turbines cannot be justified for peaking duty on the Ontario Hydro

system at the present time, although they are purchased for standby power supply at fossil and nuclear generating stations. Gas turbines have also been purchased to meet the need for additional generating capacity on short notice. All existing units are used for reserve and peaking duty, and all use No. 2 fuel oil which is both scarce and expensive. Ontario Hydro has to date a total installed capacity of about 400 MW in 36 units.

2.2.1.4 Combined Cycle, Gas/Steam Turbine Plant

Growing interest has been shown over the past few years in combined cycle plants. These plants combine gas turbines, heat recovery boilers, and a steam turbine generator into a single plant.

Since more than one gas turbine is usually employed and each has attached to it a generator, this type of arrangement is referred to as a multiple-shaft combined cycle plant.

Each gas turbine is connected by dampers and ductwork so that its exhaust gases (900°F-1000°F) are passed through heat recovery boilers. The exhaust gas heat generates steam (at pressures and temperatures of around 1250 psia and 950°F respectively) to drive a single steam turbine. The heat recovery boilers may or may not have supplementary burners; if they do not have supplementary burners, it is a purely waste-heat boiler. A simplified combined cycle diagram is shown in Figure 1. The exhaust gases of the multiple gas turbines are passed through a single heat recovery boiler. The steam output is discharged into a steam header. Valves are used to allow isolation of the heat recovery boiler and thus enable the gas turbines to operate independent of the steam turbine.

The use of gas turbine generators and steam turbine generators in a combined cycle has been advanced by the manufacturers as the best choice for meeting the so called "mid range" generation requirements, i.e. 2000-5000 hours per year with a capability for daily starting and short cycle operation. It is designed to fill the gap between gas turbines used for peaking and large steam turbines designed for base load operation.

The concept of utilizing the heat in the high temperature exhaust gas from the gas turbine to

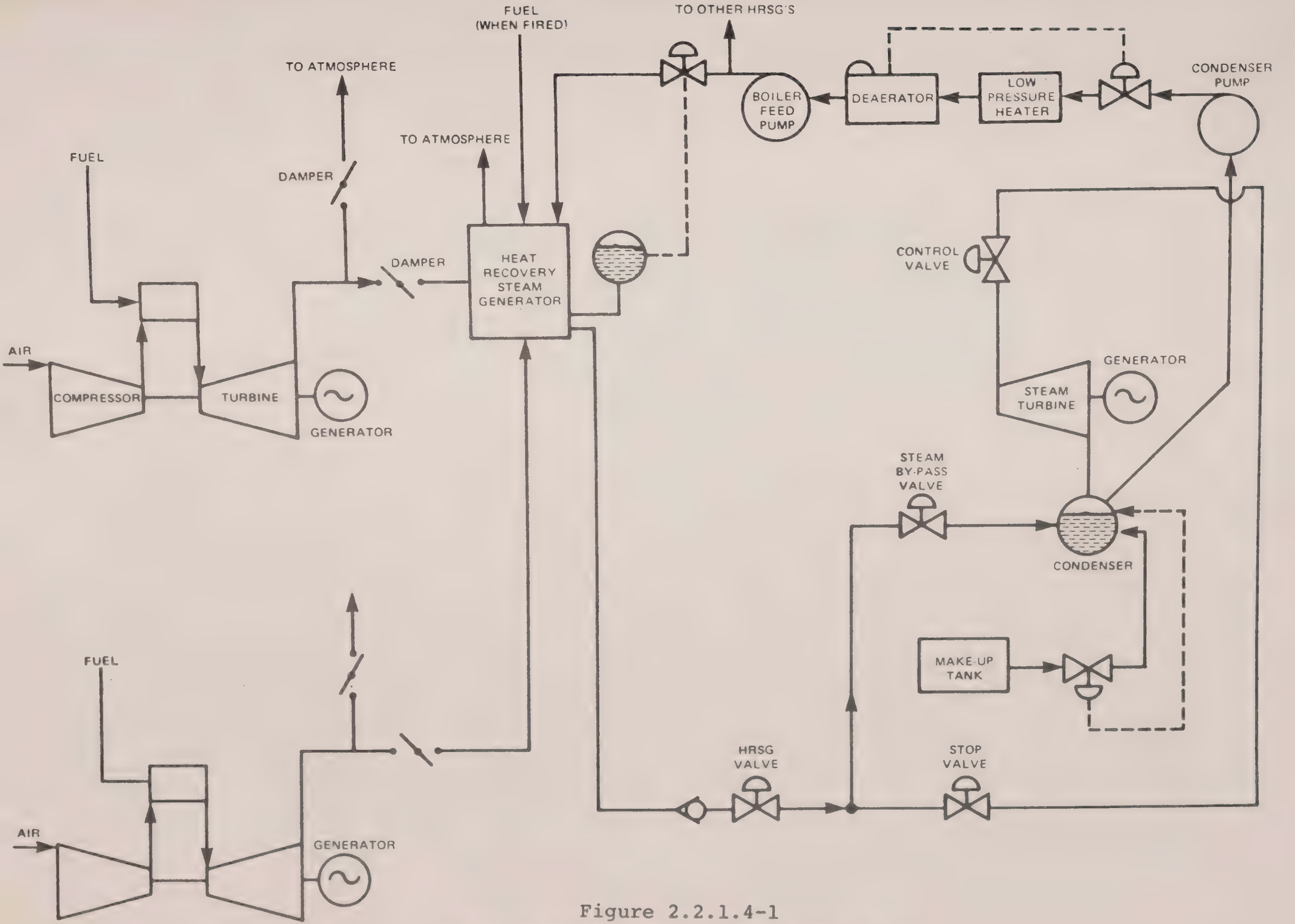


Figure 2.2.1.4-1

SIMPLIFIED MULTIPLE-SHIFT COMBINED CYCLE PLANT

produce steam in a heat recovery boiler which is then used in a separate steam cycle, is not new. Gas turbines with heat recovery equipment which produces steam for electrical power production and/or for process work are being used in the chemical industry. A good example is the petrochemical industry in the South Western United States, where there is a large demand for both electrical energy and process steam and clean fuels are available at relatively low cost.

From the point of view of the turbine industry, the combined cycle proposal is regarded as a logical development following from the recently greatly expanded production of gas turbines and their use for power production. The turbine manufacturing industry offers the combined cycle as having the advantages of the lower capital cost and shorter installation period associated with gas turbine installations plus an efficiency of about 40% which is achieved through the heat recovery and steam cycle portion and which makes the plant suitable for operation in the so called "mid range". Another advantage of a combined plant is its relatively low cooling water consumption. If the steam is generated by a purely waste-heat boiler without supplementary firing the condensate in a combined process is significantly less than an equivalent nuclear or fossil-fired steam plant; accordingly the heat rejected is also significantly reduced. For example, a 400 MW combined-cycle plant with 50% steam capacity will reject to the cooling water, approximately 3000 Btu/kw per hour at total power whereas, nuclear or fossil-fuel steam plants would reject 8,200 Btu/kw per hour and 4500 Btu/kw per hour, respectively.

Several companies have designed cycles and selected equipment which is currently being offered to the power industry. General Electric Company and Westinghouse Corporation are the leading exponents of the combined cycle in North America. The current combined cycle plant design uses the package concept and is quite different in design and proposed modes of operation from most existing combined cycle plants in North America.

In many of the existing plants, the gas turbine supplies preheated combustion air to a conventional type boiler which is capable of independent operation using a forced draft fan when the gas turbine is down. In other applications, the gas

turbine exhaust is used to heat feedwater. Here again, the steam cycle can be operated independently if the gas turbine is down.

The current GE and Westinghouse version of the combined cycle is very similar to that which Sulzer has developed and installed in Europe. These installations are the Neuchatel and Socolie plants in Switzerland and Belgium. These are about 26 MW (19 MW gas turbine, 7 MW steam turbine) and 46 MW (23 MW gas turbine, 23 MW steam turbine) respectively. They went into service in 1968 and 1969 respectively.

The most important aspect of the new combined cycle plants is that they are designed for power production. They are not conceived as schemes to use gas turbines as adjuncts to more or less conventional plants in order to increase the capability for meeting peaks; the plant being capable of normal base load operation without the gas turbines. The gas turbines are capable of operation alone or in combination with the steam turbines but they must (at least one) operate if the steam turbine is to operate to provide the combined cycle capability and the low heat rates predicted by the designers. The two main suppliers of combined cycle equipment in Canada and the United States, GE and Westinghouse, have not accumulated much operating experience yet on their equipment in a combine cycle capacity. Therefore, it would be premature to draw any definite conclusions as to the performance of these equipment at this time.

From discussions with some of the US utilities and from published reports, the following information has been obtained.

(a) There are three multiple-shaft combined cycle plants that are in operation and a fourth in partial operation, i.e. only the gas turbine portion is operational, in the U.S. so far. These are listed in Table 1 and the four plants represent a generating capacity of 1049 MWe of which 607 MWe are generated by 11 gas turbines.

(b) There are 16 combined cycle plants that are being constructed or on order. The data on total generating capacity of these plants are unavailable but the portion of power to be produced by the 82 gas turbines in these 16 plants is 5025 MWe.

(c) The Public Service Company of Oklahoma have had the gas turbine portion of their Westinghouse PACE-260 combined cycle plant in operation since 1973 and the remainder of the plant since early 1975. The plant heat rate achieved was about 9200 Btu/kw or about 37% thermal efficiency. The manufacturer's warranty for the plant heat rate was about 9100 Btu/kw. Initially, the boilers were operated dry. The firing temperature of the gas turbines are around 1875°F as specified by the manufacturer. No problems with the blading or the boiler tubes have been encountered so far due to the high firing temperature. Operating hours for the gas turbine or the steam turbine are not available to us at this time. Some problems were experienced with orifice clogging due to moisture in the gas. This situation is being carefully monitored. Boiler controls have been the biggest source of problem to date. These problems have been mostly debugged and the operation of the boilers is now progressing smoothly. Other problems encountered were failure of starter motors, BFP motors, exciters, etc. Despite these problems, utility personnel expressed optimism that the plants will operate smoothly and easily.

(d) New Jersey Power and Light Company are operating four GE gas turbines (MS7000) as a simple cycle operation until the remainder of the combined-cycle plant (STAG) is completed. The gas turbine firing temperatures are about 1850°F and the average heat rate for gas turbine is about 12600 Btu/kw. In the 3000 hrs of gas turbine operation so far accumulated, no problems with the blading have been encountered due to the higher firing temperature.

It should be noted that the need for scarce high quality liquid or gaseous fuels is an important factor when considering the simple cycle gas turbines used for peaking duty. It is even more important with the combined cycle, which is designed to operate half the hours in a year, and will thus have a much higher annual fuel consumption.

If fuel cleaning systems presently under development, can demonstrate satisfactory and economic operation using crude or residual oil, and if the reliability and maintenance costs of gas turbines can be brought to a satisfactory level, the

combined cycle will become considerably more attractive for power generation.

2.2.1.5 Efficiency of Thermal Generation Stations

The Efficiency of Heat Conversion

All heat engines transform some portion of their heat energy input to useful work, i.e. mechanical drives or electrical generation and discard a portion of the energy as low grade heat. In processes which convert energy from one form to another, efficiency is a measure of the useful output energy compared to the input energy. If the process has been developed for the highest possible efficiency with respect to the useful product, the amount and usefulness of the low grade heat will be as low as possible and will often be of no value to anyone.

In this chapter the low grade heat that is discarded or rejected from power stations is often referred to by the popular term 'waste heat'. If this term is understood to mean that a satisfactory use exists for all the heat discarded from thermal power stations, then it is inaccurate.

Energy conversion machines which have relatively high efficiencies include waterwheels, pumps, electric motors and electric generators, all capable of operation at efficiencies of above 75%. (Large electric generators operate at 98% efficiency.) In general, the loss in efficiency of such machines is caused by mechanical, hydraulic or electrical 'friction'. Since these are rather modest losses, high efficiencies can be achieved. The situation is quite different for heat engines, which convert the heat energy from fuel into mechanical energy.

The losses in efficiency of a heat engine results from the friction losses discussed above and also from limitations imposed by some of the physical laws of heat. One of these laws relates the highest achievable efficiency to the highest and lowest temperatures occurring in the machine. A fossil unit, which must operate with steam between upper and lower temperature limits of $1000^{o}F$ and $80^{o}F$, respectively, has an operating efficiency of about 37%.

The Steam Cycle for Power Generation

The conversion of heat energy to mechanical energy requires the use of stationary and rotating

mechanical equipment, and a 'working fluid'; a gaseous substance which can be pressurized and heated by fuel to raise its temperature. As the hot, high-pressure gas is passed through an engine, it expands and its temperature and pressure are dissipated. The expansion causes the engine to rotate.

The spent working fluid is removed at the point where it is 'exhausted' and is incapable of further expansion. In jet engines, gas turbines and auto engines, the spent fluid is discharged directly to the atmosphere through the exhaust pipe.

In the steam turbine cycle used for power generation, steam is the working fluid and it is continuously recycled. This recycling increases efficiency, reduces waste heat and cuts plant capital and operating costs. It also eliminates the environmental problems of steam releases to the atmosphere.

The operation of a thermal generating cycle is shown on Figure 1, and it has four main components.

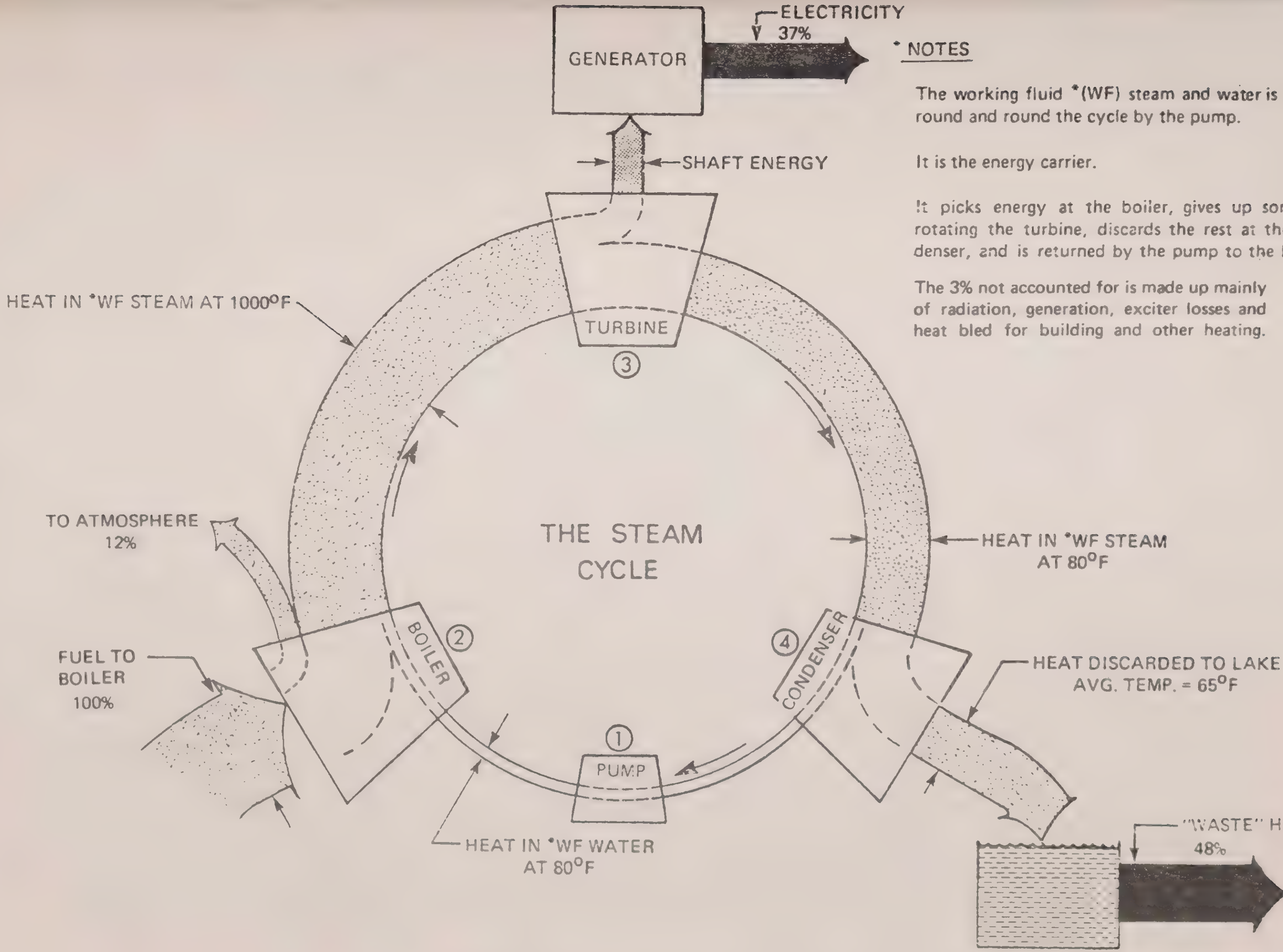
1. The pump - which pumps water from the condenser into the boiler.

2. The boiler - which vapourizes the water to steam, using heat from the fuel.

3. The turbine - which is rotated by the expanding steam and which in turn rotates the generator to produce electricity.

4. The condenser - which condenses the spent steam on metal surfaces that are cooled by lake water, and collects the water thus condensed and returns it to the pump.

The working fluid is being continuously circulated around this cycle. Each time an element of working fluid passes through the boiler it picks up heat energy. It later gives up part of this energy at the turbine for conversion to electricity, and transfers the remaining heat energy to lake water in the condenser. As each element of fluid moves around the cycle it takes on energy and gives it up again.



* NOTES

The working fluid *(WF) steam and water is moved round and round the cycle by the pump.

It is the energy carrier.

It picks energy at the boiler, gives up some by rotating the turbine, discards the rest at the condenser, and is returned by the pump to the boiler.

The 3% not accounted for is made up mainly of radiation, generation, exciter losses and heat bled for building and other heating.

FIGURE 2.2.1.5–1 DIAGRAM OF A SIMPLIFIED FOSSIL STEAM CYCLE SHOWING ENERGY FLOWS

Line Number

The Expansion Dilemma

As the working fluid progresses from the boiler, through the turbine to the condenser, it expands, so that its volume at the condenser is approximately 25,000 times its volume at entry to the boiler. This could be called the 'expansion dilemma'. For while expansion is a basic requirement for the operation of the turbine, the recycling of this huge volume of expanded steam back into the boiler presents a formidable problem.

Basically, there are three ways to solve this problem:

- The steam could be compressed in a compressor which would act like a turbine working in reverse. Unfortunately, such a system would require almost as much power as the turbine produces.

- The latent heat could be removed from the exhaust steam, allowing it to condense to water. The water would then be pumped back into the boiler -- a process that requires a relatively small amount of power.

- The exhaust steam could be discharged directly to the atmosphere, and be replaced by fresh water pumped from the lake. In this case, the steam could only be expanded to atmospheric pressure and discharged at 212°F. The result would be the discharge of more heat than occurs in a condenser, and an accompanying loss in efficiency.

The second alternative is the only acceptable choice, and cooling water from the lake is used to remove the latent heat from the exhaust steam and to discard it to the lake. The water, condensed from the exhaust steam, is drained to the pump, which delivers it to the boiler.

In a fossil fuelled generating station, about 12% of the heat in the fuel is lost in the stack gas and about 88% is used to transform water in the boiler to high temperature steam. Of this latter amount of heat, considerably more than half (typically about 48% of the total heat input) is required to provide the latent heat to transform the water into steam, and this heat must be discarded at the end of the cycle, when the steam is condensed. The remaining

40% of the heat from the fuel is used to provide sensible heat to the steam and is approximately the amount of heat that is converted to useful work. Unfortunately, the latter process cannot be performed without the former.

Distribution of Energy Flows

As indicated previously, Figure 1 illustrates the operation of a fossil fired generating cycle. Figure 2 is a comparable diagram for the Candu cycle. Figure 3 shows the heat added, converted and discarded for the Candu cycle and Figure 4 illustrates the relative volumes of the working fluid for the Candu cycle. The size and distribution of energy flows in the Lennox oil-fired station are given on Figure 5, with similar data for Pickering presented in Figure 6. Note that all of these energy streams are in the form of heat except for the power to the generator (shaft power), and the generator output (electricity). The size of each stream is shown as a per cent of the total heat recoverable from the fuel in the furnace or reactor.

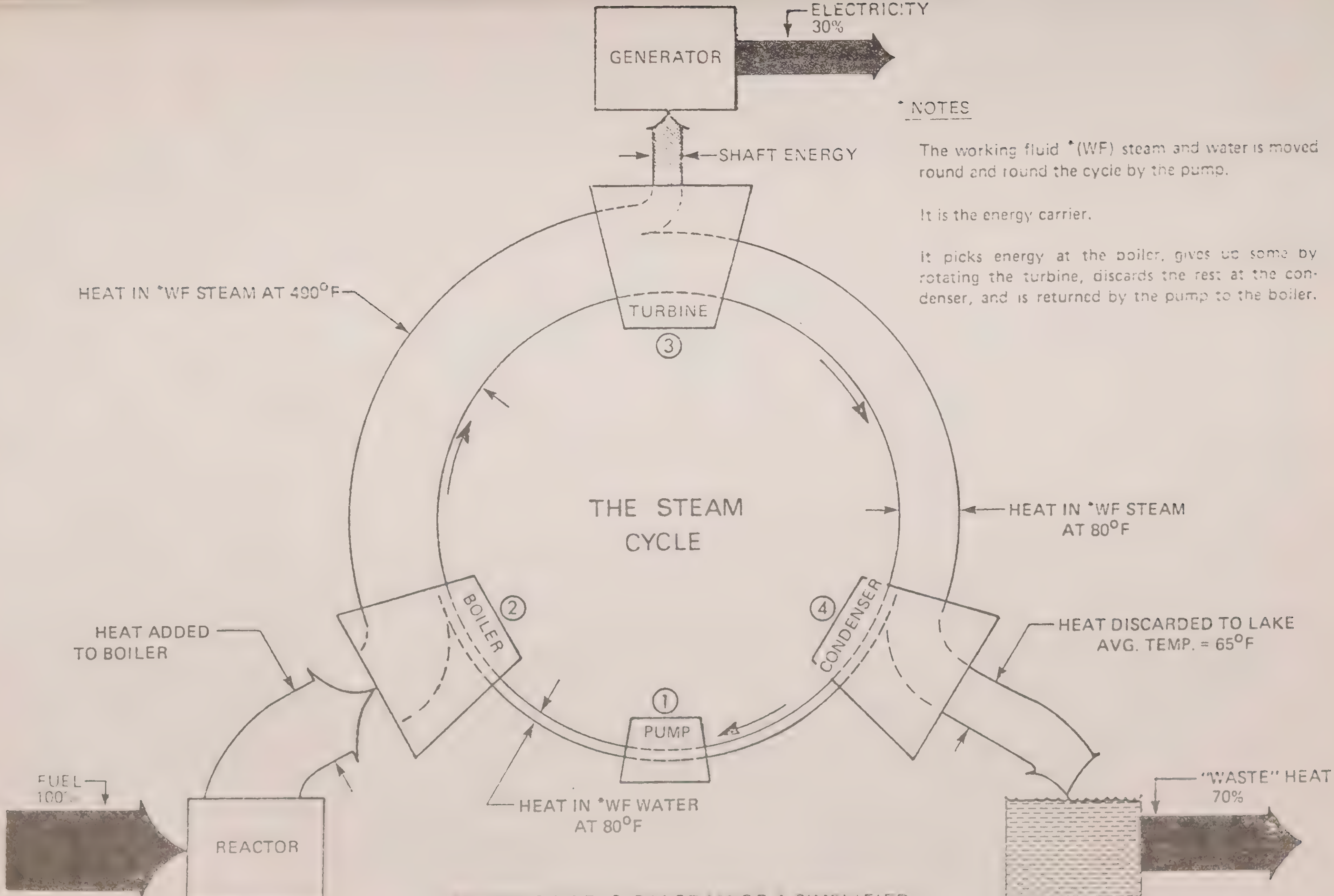
The Improvement of Efficiency

The latent heat discarded in the cooling water from the thermal generating stations has long been recognized as a productive area for improving efficiency, and a number of features have been designed to reduce it. These are discussed below along with other alternatives for improving cycle efficiency.

- It has been common practice for many years to use as much of the latent heat as possible to reheat the feedwater before it enters the boiler. Through use of the latent heat in about one third of the steam that would otherwise be exhausted, the cycle efficiency is raised to 38%.

- The amount of discarded heat can be reduced by lowering the temperature at which the steam is condensed. In Ontario, the cold waters of the Great Lakes result in very low condensing temperatures and thus better overall efficiencies than for generating stations in most other locations.

- The steam cycle efficiency can be raised by increasing the temperature of the steam. In



* NOTES

The working fluid *(WF) steam and water is moved round and round the cycle by the pump.

It is the energy carrier.

It picks energy at the boiler, gives up some by rotating the turbine, discards the rest at the condenser, and is returned by the pump to the boiler.

FIGURE 2.2.1.5–2 DIAGRAM OF A SIMPLIFIED CANDU STEAM CYCLE SHOWING ENERGY FLOWS

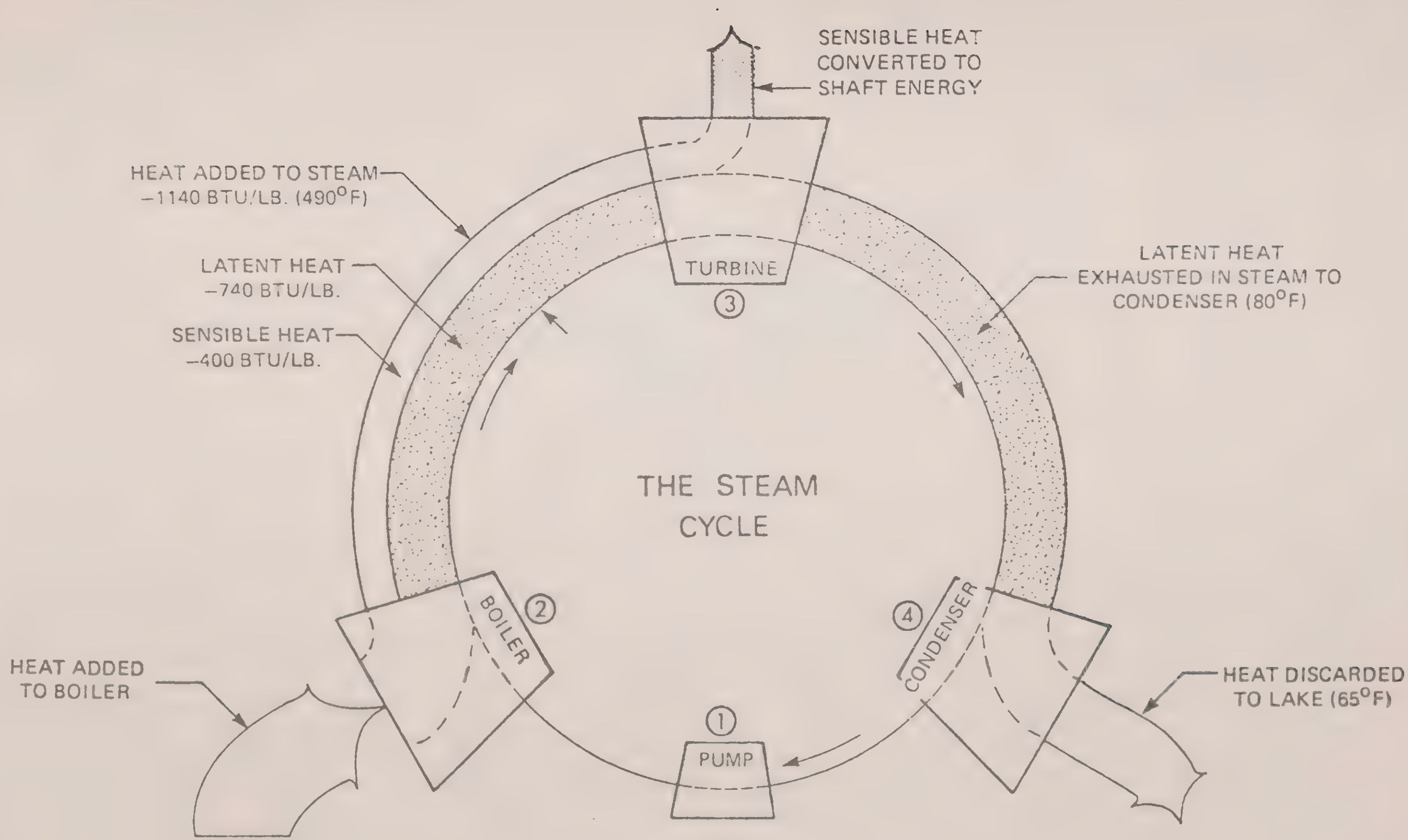


FIGURE 2.2.1.5–3 DIAGRAM OF A SIMPLIFIED CANDU STEAM CYCLE SHOWING HEAT ADDED, CONVERTED AND DISCARDED

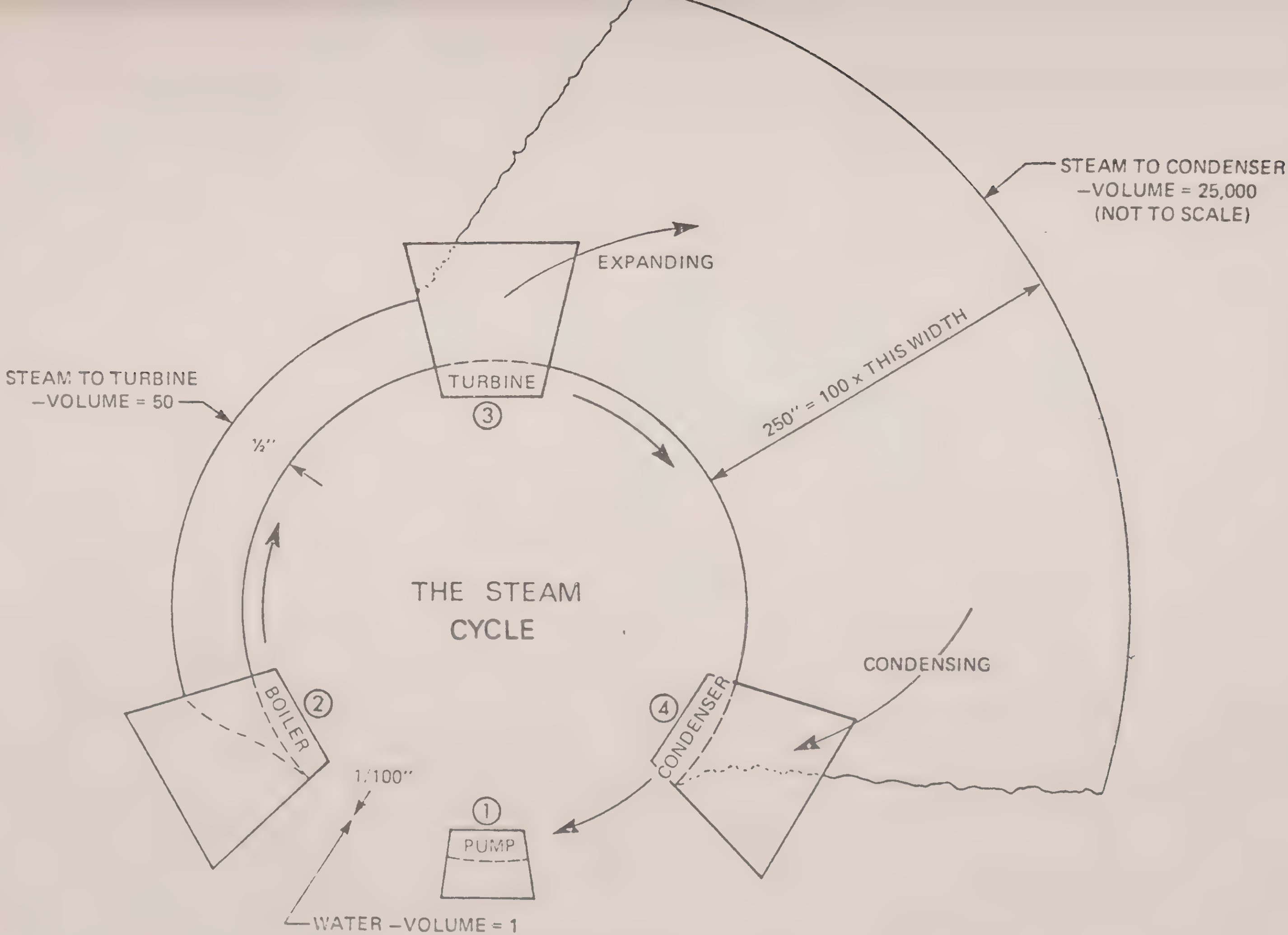


FIGURE 2.2.1.5–4 DIAGRAM OF A SIMPLIFIED NUCLEAR STEAM CYCLE SHOWING RELATIVE VOLUMES OF THE WORKING FLUID

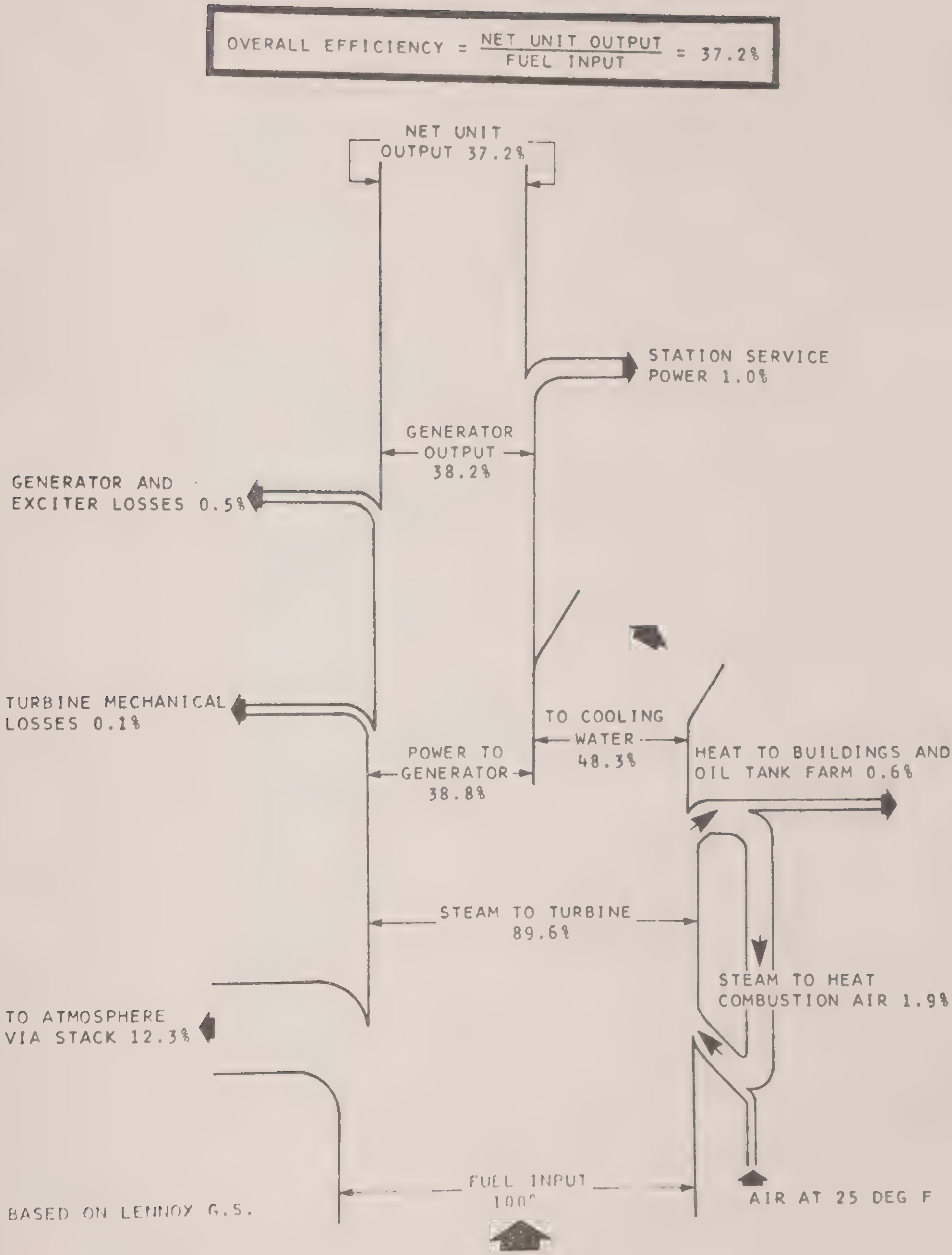


Figure 2.2.1.5-5

Heat Distribution in a Typical Fossil Fuelled Generating Station

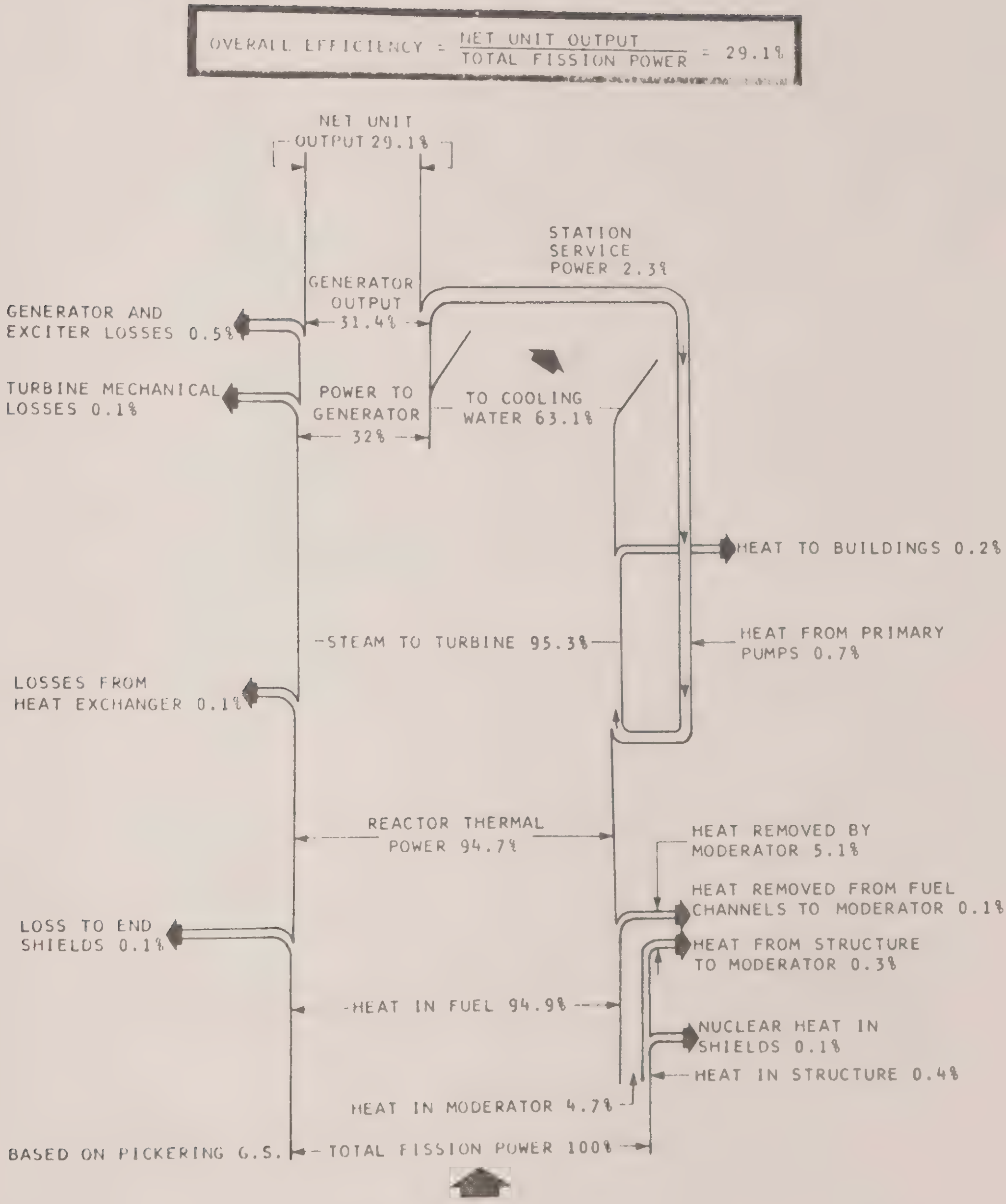


Figure 2.2.1.5-6

Heat Distribution in a Typical Nuclear Fuelled Generation Station

practice it is limited by the ability of materials to retain strength at higher temperatures and pressures. For example, in spite of a great deal of metallurgical research over the years, there has been a stabilization of steam temperatures for fossil-fuelled generating units at about $1000^{\circ}F$. In a Candu nuclear unit the limiting metal temperature is at the fuel sheath, and this controls the steam temperature to less than $490^{\circ}F$.

- Other minor improvements to steam cycle efficiency are possible, which can only be achieved through a disproportionately high increase in capital cost or by affecting the reliability of the equipment.

- The use of working fluids other than steam may improve efficiency. The most common of these is the heated air used in a gas turbine fuelled with light oil or natural gas. However, the gas turbine has not yet surpassed the steam turbine in efficiency nor has it yet been used to generate power from nuclear fuel. Instead it generally uses the most expensive of the fossil fuels.

- Many other more complex working fluids continue to be investigated, but years of development will be required to bring a promising one to commercial reality, once it has been identified.

The utility industry is continuously studying other generating processes to improve efficiency. But it is difficult to identify a system which has sufficient probability of success in future use to commit the very large expenditures of time and resources needed for its development. Thus the promise of a significant improvement in efficiency of the thermal generating process in the near future is not high.

TABLE 2.2.1.5-1

Commercially Available Thermal Generation Equipment

	Normal Fuel	Alternative Fuels++	Electrical Production Efficiency %	Energy Released Per Unit of Electricity Produced		Maximum Unit Size MW	Most Appropriate Modes of Operation
				(a) to Cooling Water	(b) to Atmo-sphere		
Sub-Critical Fossil-Steam	Coal	Gas or Bunker Oil	38	1.3	0.3	900*	Intermediate or Peaking
	Bunker Oil	Gas or Crude Oil	38	1.3	0.3	"	"
	Crude Oil	Gas or Bunker Oil	38	1.3	0.3	"	"
	Gas	Bunker Oil	37	1.3	0.4	"	"
Super-Critical Fossil-Steam	Coal	Gas or Bunker Oil	39	1.3	0.3	1300+	Base
	Bunker Oil	Gas or Crude Oil	39	1.3	0.3	"	"
	Crude Oil	Gas or Bunker Oil	39	1.3	0.3	"	"
	Gas	Bunker Oil	38	1.3	0.3	"	"
Gas Turbine	#2 Oil	Gas	29	0.0	2.4	100	Peaking or Reserve
	Gas	#2 Oil	28	0.0	2.6	"	"
Gas Turbine/ Steam Turbine	#2 Oil	Gas	40	0.8	0.7	500	Intermediate or Peaking
	Gas	#2 Oil	39	0.8	0.8	"	"
CANDU Nuclear	Uranium	-	30	2.3	0.0	1250	Base

* Apparent limit on size of a tandem compound steam turbine (using a single generator).

\+ Apparent limit on size of a cross compound steam turbine (using two generators).

++ Unless a unit is specifically designed to burn alternative fuels, considerable equipment modification may be required.

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2.2.2 Fossil Fuels

2.2.2.1 Use in Power Boilers

This section will consider quantities needed and the quality of available fossil fuels, their effects on the environment and the limitations of the combustion equipment used in converting these fuels into electrical energy.

(a) Projected Consumptions

FORECAST OF ANNUAL FUEL USAGE (DECEMBER 1975)

1975 - 1995

Year	Coal Million U.S. Tons Equivalent	Residual Oil Million Bbl	Natural Gas Bcf	Other Oil Million Bbl
1975	7.6	1.3	55.7	0.05
1980	16.5	13.7	49.	0.09
1985	17.5	12.9	49.	0.31
1990	21.6	10.5	49.	0.38
1995	28.7	10.0	49.	0.56

(1)

(b) Quality of Available Fuels

Natural Gas

Natural Gas is a high quality fuel which burns easily and cleanly and therefore is in demand as a domestic and an industrial fuel. It is also valuable as a basic feedstock for the plastics industry. Because of these demands its use is restricted as a boiler fuel. Ontario Hydro burns gas in a portion of the boilers of only one station, the R.L. Hearn GS in Toronto.

Residual Oil

Residual oil is the residue remaining at the end of the crude oil distillation process, when

the lighter products, such as gasoline and distillate oils have been removed. It is a sticky, tar-like substance with limited uses, but is a good boiler fuel. It can be transported most readily by boat but can also be moved by rail. Because it has to be kept hot for pumping it is difficult to move through long pipelines.

Residual oils have relatively low ash levels (about 0.1%), high heating values, very low moisture content and are relatively easy to handle and burn. The sulphur content can vary upwards from 0.5% depending on the origin of the crude oil.

Ontario Hydro presently has one generating station in operation fired by residual oil. This is Lennox GS which burns a residual oil containing about 2-1/2% sulphur derived from Venezuelan crude oil. A second generating station, Wesleyville, is also being designed to burn residual oil. It is expected that this fuel will be obtained from Canadian crude oil and will have a sulphur content of about 0.7%.

Crude Oil

Both Lennox and Wesleyville stations are designed to burn whole crude oil as a back-up fuel. The sulphur content of crude is generally lower than that of the residual oil derived from it.

Coal

In the past, all of Hydro's fossil fired steam generation was based on coal from the Appalachian region of the United States. This is a high quality steam coal which has low to medium sulphur content, good combustion characteristics, relatively low ash and good grindability. It is relatively easy to handle and unload from rail cars and boats and does not generate much dust, in comparison to other coals. A range analysis (proximate) for this type of coal, which Hydro purchased in 1973 and a trace element analysis is as follows.

Proximate Analysis - U.S. Bituminous Coal

Moisture	%	3.3	6.3
Ash	%	6.7	13.6
Volatile	%	31.3	38.1
Fixed Carbon	%	48.7	54.5
Calorific Value	BTU/lb	11,978	13,638
Sulphur	%	1.4	3.1 (2.4% average)

TRACE ELEMENT ANALYSIS
U.S. Bituminous Coal
ppm

Element	Average	Element	Average
Ag	1.7	K	1056
Al	9265	La	4.6
As	12	Lu	0.14
D	16	Mg	305
Ba	133	Mn	22
Be	0.88	Na	456
Br	13	Ni	3.1
Ca	3175	Pb	6.1
Cd	0.28	Rb	12
Cl	1106	Sb	0.43
Co	3.1	Sc	2.9
Cr	12	Se	2.7
Cs	0.71	Sm	1.0
Cu	5.0	Sn	3
Dy	0.99	Sr	113
Eu	0.28	Ta	0.31
F	78	Tb	0.32
Fe	5333	Th	1.2
Ga	9.0	Ti	473
Hf	0.63	U	0.70
Hg	0.32	V	18
I	1.0	W	0.41
In	0.2	Yb	0.40

For security of supply considerations, Hydro plans to purchase substantial amounts of Western Canadian coal, commencing with about 2 million tons in 1978 and increasing to about 4 million tons by the early 1980's. These coals have less desirable combustion characteristics, namely lower heating value, higher ash content and in some cases low volatile content. Some of these coals also tend to be friable which necessitates increased precautions for dust during transportation and handling. They have also proven to be difficult to unload from boats, because of poor flow characteristics. Western Canadian coal is low in sulphur. Typical proximate analyses of two coals we expect to purchase in the future and a trace element analysis are as follows.

Proximate Analysis	Byron Creek	Coal Valley
Moisture ....%	1.0	8.0
Ash ....%	18.5	10.5
Volatile ....%	21.3	34.7
Fixed Carbon ....%	59.2	46.8
Calorific Value ....BTU/lb	12,020	11,000
Sulphur ....%	0.5	0.3

TRACE ELEMENT ANALYSIS
Western Canadian Coal
ppm

Element	Average	Element	Average
Ag	0.28	K	613
Al	15168	La	8
As	2.1	Lu	0.2
D	–	Mg	360
Ba	385	Mn	12
Be	0.5	Na	232
Br	1.8	Ni	3
Ca	1982	Pb	1.0
Cd	0.27	Rb	–
Cl	375	Sb	0.7
Co	2	Sc	5
Cr	4	Se	1
Cs	0.6	Sm	1
Cu	2	Sn	–
Dy	–	Sr	127
Eu	0.8	Ta	0.9
F	97	Tb	0.6
Fe	1245	Th	2
Ga	5	Ti	903
Hf	2	U	1.3
Hg	0.3	V	22
I	1.2	W	–
In	0.2	Yb	0.6

(c) Environmental Factors

Natural Gas

Natural gas is essentially free of ash and sulphur, so that there are no emissions of sulphur dioxide or particulate. However, in common with other fuels, oxides of nitrogen form during the combustion process. Recently developed modifications to boiler design have resulted in reduced emissions of nitrogen oxides with this fuel.

Natural gas is transported from its source to destination by pipeline. Environmental effects associated with its transportation are generally confined to the period when the pipeline is installed.

Residual Oil

Residual oil contains only small quantities of ash, so that particulate emissions are low. However, the particle size of these emissions is such that a visible plume results. Ontario Hydro installs electrostatic dust collectors with the objective of achieving an essentially clear plume, although a water vapour plume is visible during cold weather. The quantity of ash collected by the dust collectors is very small and its disposal does not present an environmental problem. In the case of Lennox GS, the collected ash is being sold to a chemical processing company which extracts vanadium from it.

Hydro is buying 2-1/2% sulphur residual oil for Lennox GS and expects to burn 0.7% sulphur residual oil at Wesleyville GS. Both stations are designed to operate well within the provincial regulatory requirements with respect to sulphur dioxide.

Some oxides of nitrogen are formed during the combustion of oil as is the case of other fossil fuels. Fuel oils can be burned with relatively low levels of excess air (3%-5%) and this limits the amount of oxygen available to combine with the nitrogen and reduces the nitrogen oxide emissions. Hydro's oil fired stations are designed for low excess air and ground level concentrations of nitrogen oxides are well within Provincial regulations.

Residual oil will be transported to our generating stations in rail cars, and will be stored in large covered tanks or underground caverns. These systems are designed for low environmental effects.

Crude Oil

The effects of crude oil on air quality are generally less than for residual oil. The oil is delivered by pipeline and stored in covered floating roof tanks or underground storage caverns.

Coal

The ash content of the coals Hydro expects to purchase is likely to range from a low of about 5% for some Appalachian coals to a high of 18%

for some of the Western Canadian coals. By blending low sulphur Western Canadian coal and medium sulphur U.S. coal it is expected that existing particulate removal efficiencies of 99 to 99.5% can be maintained. Except for cold weather conditions, this results in essentially a clean plume which is well within the Provincial regulatory requirements.

The ash from coal fuels is used for structural materials or as a land fill. The former use is growing. Where no other use can be found, Hydro landfills the ash at the operating site, or it is transported in covered trucks to other landfill areas. It is Hydro's policy to dispose of this ash in landfill sites in an environmentally and aesthetically acceptable manner, which will improve the future value of the land.

The medium sulphur content (2) of some of the Appalachian coal we purchase results in sulphur dioxide emissions from the stacks. The effects of these emissions can be reduced by building tall stacks to disperse and dilute sulphur dioxide concentrations before they return to ground level. The emissions can be reduced by the use of low sulphur fuels. It is expected that the low sulphur Western Canadian coals to be purchased by Hydro will be blended with the medium sulphur Appalachian coals to yield a sulphur content of about 1.5 to 1.7%.

All Hydro's coal is delivered to the generating station by boat and since it is covered, there is no opportunity for dust loss during this phase of its transportation. During handling and storage at the station, some dust is generated due to movement of mobile equipment over the coal piles. This is controlled by water spraying, as necessary, so that little dust escapes beyond the generating station boundaries. The Western Canadian coals are likely to generate more dust than the Appalachian coals we presently use and more spraying may be required to control the dust (3).

These Western Canadian coals will be moved by rail from Western Canada to Thunder Bay in open rail cars. It is planned to spray the coal surface in each car with a bitumastic solution, which forms a crust and prevents loss of coal dust.

Oxides of nitrogen are generated in coal-fired boilers as is the case with oil and gas. Less success has been achieved in developing methods to reduce nitrogen oxides from coal-fired furnaces than with oil or gas, but though the emissions of nitrogen oxide vary significantly from one boiler to another, all Hydro's coal-fired stations are able to continually meet the Provincial regulations for nitrogen oxide concentrations.

(d) Limitations of Combustion Equipment

Natural Gas

Because of its gaseous nature, natural gas is fired directly in to the steam generator furnace, thus eliminating the need for fuel handling and treatment equipment. The gas is withdrawn as required from the supply system, so that no storage facilities are required at the generating station site. The clean nature of the fuel eliminates the need for particulate collection equipment and soot-blowing equipment too. All these factors contribute to low capital and operating costs (other than fuel costs) for gas-fired installations. Though this is the least expensive form of fossil-fired generation, because of its value as a domestic fuel and because of dwindling natural gas reserves, future security of supply is likely to be poor. Ontario Hydro has no generating stations designed to burn natural gas exclusively.

Residual Oil

As noted previously, residual oil is a heavy tar-like substance which is difficult to pump over long distances. Consequently, rail transportation is used to deliver residual oil to Lennox GS. A substantial amount of storage is required to absorb differences in the rate of fuel delivery and consumption as well as to cover the eventuality of loss of fuel delivery for a period, or an unforseen demand on the generating station.

The oil is moved from storage to the furnace by a pipeline system, which pressurizes the oil so that it is atomized as it passes through the burners into the furnace, where it is ignited.

The small amount of ash in the oil forms some deposits on the boiler surfaces, requiring a soot-blowing system for its removal. The size distribution of the fly ash, which would be emitted in the flue gas stream, is such as to produce a noticeable plume, requiring an electrostatic precipitator to ensure meeting the Provincial Air Quality Regulations. Also, some of the constituents of the fuel, sulphur and vanadium, particularly, can form corrosive compounds which attack the boiler tubes. Chemical additives often have to be added to the oil to prevent corrosion of this nature. An oil-fired boiler requires just about the same furnace volume as that required for gas firing.

All the additional requirements of storage facilities, pumping facilities, soot-blowers and ash collection equipment result in a higher capital and operating cost (other than fuel cost) for an oil-fired installation, in comparison to a gas-fired installation.

Boilers designed for oil firing can be converted to gas at some cost. Conversion to coal firing is both difficult and costly and would result in a substantial loss of output.

Coal

Coal is a solid fuel, and therefore, has to be ground to a very fine consistency (70% passing 200 mesh) before it can be fired in a boiler which burns it in air suspension. This requires the installation of pulverizers to reduce the coal to the required size. As with residual oil, a stock pile of the fuel is required to absorb differences in the delivery and consumption rates and to provide contingency storage against the possibility of interruptions of the delivery system or sudden increased demand on the generating station. In our particular situation, where coal supplies are delivered by boat, a storage pile must be built in the summer and fall to provide fuel for the winter season, when coal delivery is not possible. Though coal does not require storage tanks, and is simply stockpiled outside, reclaim equipment is required to move the coal from storage when needed, additional property is needed for the storage and there is

a significant cost attached to the maintenance of fuel inventory for winter and contingency requirements. These storage piles must also be properly compacted to prevent spontaneous combustion and sprayed as necessary with water to limit dust emissions. Coal reclamation and pile maintenance require a substantial work force and incur an operating and maintenance charge.

The relatively high ash content of coal tends to cause more boiler slagging than is experienced with oil-fired units and thus required more soot-blowing equipment to maintain the furnace and convection passes in an adequately clean condition. The higher slagging rates also increase the bottom ash production and require larger bottom ash handling equipment. Fly ash removal equipment must also be larger than that required on oil-fired units. Ash disposal facilities must also be provided, and with the relatively high ash content of coal, a large area is required to dispose of the ash generated in the station lifetime. This requires additional capital and operating expenditures.

Coal bunkers must also be provided, to ensure a steady flow of coal to the pulverizers and belt scales are provided, so that the flow of coal to the pulverizers can be measured and controlled. Furnace volumes for coal-fired units are much larger than those required for oil or gas. This and the addition of pulverizing equipment and coal storage facilities within the boiler house not only adds to the capital and maintenance cost of the boiler but also adds to the building size required to house all this equipment, further adding to the capital cost of the station. Coal-fired boilers are the most costly of the three alternative fossil fuels.

Coal fired units can be converted to either oil or gas firing at some cost and a small loss in efficiency.

2.2.2.2 Coal Slurry Pipelines

Solids pipelining has had limited application in various parts of the world mainly in the mining industry and it has involved relatively short lines.

The movement of coal as a slurry in a pipe was first investigated in North America as an alternative to rail transport. Only two lines have been built to date, both designed to carry a coal water slurry. The first line from Cadiz, Ohio to Cleveland Electric Illuminating Company's East Lake Station on Lake Erie ran 108 miles and had a capacity of 1.3 million tons per year in a 10" pipe. It was built by the Consolidated Coal Company and began operation in 1957. It was abandoned in 1963, when rail tariffs were lowered. The second line located in Arizona came into commercial operation in 1971 and is still operating. It transports coal from Black Mesa Mine to the Mohave Generating Station of Southern California Edison, a distance of 273 miles. The capacity is about 4.8 million tons through an 18" pipe. In addition to this a number of studies have been carried out or are under way involving pipeline proposals to carry coal from the Western U.S.A. to the East and South of that country.

In Canada a number of organizations have carried out studies of pipelining coal in either oil or water. This has included both experimental work at research facilities and economic evaluations of proposed full scale models.

Most of this work has been done with coal in water slurries as this is favoured over coal/oil principally because the separation problems, while still formidable with a water slurry, seem more amenable to a technical and economically acceptable solution that the coal/oil slurry. The Saskatchewan Research Council is currently completing a coal/oil study for the federal Transport Development Agency.

There is confidence among designers and operators of coal slurry pipelines that sufficient knowledge exists to permit the building and successful operation of long (1,000 miles and more) and large, 20-30 million tons/year pipelines. Experience in similar large projects however might suggest that extrapolation from the present 273 mile line operating in Arizona to distances of 1,000 miles under Canadian weather and topography could produce unforeseen problems. However the Black Mesa line does appear to transport coal successfully. Separation of the coal at the delivery end appears to be a more serious problem at Black Mesa. Reports from there and other sources indicate that development of a satisfactory method of separation to produce a suitable product for power plant use

has not yet been achieved. The problems associated with coal/oil separations are even more difficult if it is accepted that it is necessary from the points of view of economics and conservation of a valuable energy source to remove practically all of the oil from the coal before burning. This means it would be necessary to develop a refinery process to accept the coal/oil slurry and separate the components to produce acceptable coal and oil products.

The economic evaluations of pipelines are usually made on the basis of comparison with rail transport. The cost per ton of pipelining coal is very sensitive to the through-put. The results therefore are most often summarized in the form of a statement giving the yearly pipeline through-put required in order to achieve parity with the rail alternative. While figures produced vary it appears that for the case of moving Western Canadian coal to the Lakehead at Thunder Bay there is reasonable agreement that at least 10 million tons yearly are required in order to warrant serious consideration. Slurry pipelines cannot be operated at part capacity (experience seems to indicate no lower than 85%) so it is not feasible to plan installation of an economically competitive size with the object of running it at reduced capacity while building load.

The present indications are that the projected quantities of Western Canadian coal which could be transported to Eastern Canada for the next ten years at least are insufficient to warrant serious planning of an installation at this time.

The main concerns about a slurry pipeline system as a means of delivering fuel to a central generating station are, as indicated above, development of a means of separation which will deliver an acceptable fuel to the boiler, and reliability of the system since it would directly effect the reliability of the generating system. For either existing stations or new stations considerable development could be required to develop means of handling this fuel into the boiler. Problems of storage to do with the amounts and methods would also require solutions.

2.2.2.3 Refuse Fuels

(a) Introduction

The amount of material discarded today is a concern to most people. The value of refuse

can be considered from a number of points of view. Probably the most important is the recovery of materials and energy. The combustible materials may be recovered either for their material value or for their heat energy value. The choice of these forms will depend on many factors, including the cost of recovery and the predicted future value of each commodity.

This discussion will be confined to the recovery of energy from refuse with particular reference to the generation of electricity.

(b) Heat in Refuse

Ordinary household refuse contains from 3000 to 5000 BTU's of heat per pound. While this is only 1/3 of that found in U.S. coal, it is higher than the heat derived from many lignite coals used in Europe for power generation.

The following table provides a perspective of the energy in refuse in Ontario. While it is small compared to total electrical use, it is an important energy resource.

Line Number

An Estimate of the Energy Content of Refuse in Ontario for the Year 1975

1.	Total commercial and residential refuse	6,000,000 tons
2.	Average heat content per ton	9 MMBTU
3.	Heat in total refuse	54,000,000 MMBTU
4.	*Recoverable heat (60%)	32,000,000 MMBTU
5.	Amount of U.S. coal equivalent to the recoverable heat	1,100,000 tons
6.	Electricity that could be generated from Item 5	3,000,000 MW hrs
7.	Item 5 as a percent of Ontario Hydro's coal use	15%
8.	Item 6 as a percent of Ontario's electricity use	3-1/2%

*This estimate assumes that;

- Processing and transport of refuse fuel for heat recovery is unlikely to be an alternative for some smaller communities.
- Some of the combustible in refuse has a material resource value that is higher than its energy value and will be recovered.
- In preparing refuse fuel a portion of the combustible is lost during the separation process.

(c) Refuse as Fuel

As a fuel, refuse contains adequate heat, but it also has constituents which must be recognized in the development of any process to use this heat.

In general it contains:

- a large proportion of plastics and paper from which it derives its fuel value
- non combustibles, including glass, tin cans, and structural components, that are difficult to process
- decomposing materials
- explosives in the form of partially filled propane bottles, etc.
- a wide array of chemicals
- moisture.

The composition is generally predictable over the period of a week or month but may vary quite widely from day to day. The long term change in its general composition is less predictable, and refuse from future new products could be difficult to handle in equipment designed for today's refuse.

(d) Types of Refuse Fuel

The development of refuse fuel is still in its infancy and much work is in progress. Some types of fuel receiving attention are listed in the order of their general development:

- whole refuse
- shredded and classified refuse
- liquified refuse
- gasified refuse.

Regardless of the type of fuel derived, the release of heat from the refuse involves some common factors. As with any other fuel, the chemical elements in the combustible refuse are

all converted to hot gases in the incinerator, furnace or boiler, and these are either scrubbed or diluted before release to the atmosphere. Refuse is more difficult to use than normal fuels because its chemistry is more diverse and less predictable, and is highly corrosive to high temperature metals.

There are other factors which are more important for some refuse heat recovery processes than for others. These include material handling and storage, particulate collection from the furnace gases, and the handling and disposal of the ash and unburned residue. Thus, the type of heat recovery process selected will have quite different effects on air and water quality.

(e) <u>Markets for Heat From Refuse</u>

The markets most often considered for heat from refuse are electrical power and space heating. Each of these has its own peculiarities with regard to the heat recovery process.

In fitting the market demand to the heat supply from refuse, it is noted that the amount of,

- heat supply from refuse is constant throughout the year

- electrical demand is slightly lower in summer than in winter

- heat demand for domestic and commercial space heating is sharply lower in summer.

Since electricity derived from refuse is small in relation to total electrical use, and since the generated power would be delivered into a large electrical network, there is no need to provide 'back-up' power generation during a breakdown of the refuse burning plant.

Supply of heat, on the other hand, requires a reliable source and most European district heating incinerators have 100% backup heat supply in the form of standby oil-fired boilers. Cooling towers are generally provided, as well, to discard the heat during the early market building years and during summer months when there is little heat demand.

For the above reasons, electrical generation may seem to be the most economic way to use the heat at a refuse incinerator. However, the corrosion problem mentioned in paragraph 4 has a marked influence on this decision.

High temperature steam (800-1000°F) is required to obtain high efficiency in a steam turbine-generator. These steam temperatures require even higher boiler tube metal temperatures. A number of refuse burning plants which have attempted to operate at these high temperatures have had unbearable high-temperature corrosion rates. New installations generally use a steam temperature of less than 600°F.

This upper limit on steam temperature makes power generation at an incinerator considerably less efficient and, therefore, less economic. Some combined power and heat supply systems are being built, but in other instances they apparently cannot be justified, and the output of the incinerator boiler is limited to providing hot water for district heating.

(f) <u>District Heating Incinerators</u>

The supply of heat to district heating networks in certain parts of Europe is augmented by heat from incinerator boilers. The public acceptance of such facilities on the edge of new residential suburbs, appears to some as a commendable assent to reality. However, such acceptance has not been the recent experience in urban Ontario.

(g) <u>Watts from Waste</u>

In the above discussion the burning of undiluted refuse has been considered and the problems of its chemistry discussed.

Watts from Waste is a process for firing beneficiated refuse fuel into a large utility power boiler under controlled conditions. The normal coal fuel provides 85 to 90% of the total heat requirement and the refuse fuel supplies 10 to 15%. The refuse fuel would be prepared at a municipal processing station by shredding the whole refuse and separating the light combustible fraction from it. This fraction would consist mainly of paper and

plastic products, and would account for more than 75% of the weight of the whole refuse and probably 95% of its volume.

Following separation, the refuse fuel would be transported to the generating station. The remaining heavy fraction, which contains a large proportion of non-combustibles, would be directed to land fill following the recovery of any materials that may be appropriate.

This dilution of refuse fuel with coal in the boiler is believed to have several beneficial effects:

- The hot gases from the coal and refuse mix, and the concentration of chemicals from refuse is reduced to the point where high temperature corrosion either does not occur, or occurs at an acceptable rate.

- The diluted gases from the refuse leave the tall power station stack with the large volume of heat from the boiler gases, and are assured a plume rise that is adequate for their dispersion.

- The refuse heat is used to generate power at high efficiency.

Ontario Hydro has agreed to undertake a 2 year demonstration of this system on one unit at Lakeview. The in-service date is scheduled for early 1978. Its capacity is about 100,000 tons of refuse fuel per year which is about 8% of the fuel content in all the residential and commercial refuse from Metro for 1975.

During the demonstration, the Lakeview station staff and Hydro's Research Division will monitor and analyse the boiler metals for any indication of the onset of corrosion. Such an event could terminate the demonstration.

The ability to collect flue gas particles will also be monitored, as well as, the nature and amount of ash from the bottom of the furnace. Considerable development work is still needed, but it is expected that the trials will be successful and will show that additional boilers can be committed to this service in future.

(h) <u>Summary and Conclusions</u>

The estimated recoverable heat energy in refuse in Ontario is equivalent to about 15% of that contained in the coal used by Hydro annually. If all of this heat were used to generate electricity, it would supply 3-1/2% of the Ontario demand.

There are a number of factors which limit the use of heat from refuse, the most important being its chemistry and the high capital cost of processing equipment.

Much has yet to be learned, but at present the best opportunities for heat recovery from refuse may be in:

i) Supply of heat to a district heating network using low temperature incinerator boilers fired with whole refuse and located in or near urban areas. Such installations would likely need 100% back-up from oil-fired boilers in case of breakdown. Local public acceptance of the refuse delivery system and tall stacks will be needed.

ii) Production of electricity at coal-fired generating stations using the Watts from Waste system, providing that the currently planned Lakeview program demonstrates feasibility. The refuse fuel would be beneficiated by shredding and classifying, and its delivery to remote coal-fired stations could be by rail.

iii) Production of liquid fuels which could be used in individual heating boilers.

Ontario Hydro's interests under its present mandate would be directed to the Watts from Waste approach.

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2.2.3 Cooling of Generating Stations

2.2.3.1 Once-Through Shoreline Discharge

i) Ontario Hydro Position on Once-Through Cooling Using Great Lakes Water

Thermal Generating stations, both fossil fuelled and nuclear, use the waters of the Great Lakes for two main purposes: for the production of steam for the turbine, and for cooling and condensing steam at low temperature and pressure and the removal of this reject heat from the station. The first use requires a very small amount of water, normally held in a closed circuit. The second use requires large amounts of cool water to efficiently remove between 50 and 70 percent of all the heat produced at a generating station and to dispose of this very low grade heat to the ultimate heat sink, the atmosphere.

Ontario Hydro now has approximately 13,000 MWe of thermal plant (fossil and nuclear) in operation, 8,700 MWe under construction and another 7,200 MWe expected to be approved for construction in the near future, all using Great Lakes water for cooling. All operating and committed stations and those planned for commitment in the near future utilize a shoreline surface discharge of warm water. The intakes for the early stations were at the surface near the shoreline, however, for all recent projects off-shore bottom intakes are used.

The withdrawal from and the return to the lake of the cooling water at elevated temperatures has been the subject of extensive discussions between the regulatory agencies and Ontario Hydro, with respect to the possible effects on the ecology of the lake.

Ontario Hydro has been undertaking a broad investigational program, in cooperation with other agencies, involving studies of our once-through cooling systems. We have now compiled a substantial amount of data on the physical and biological effects due to our cooling arrangements and have an extensive continuing investigational program which was also recently

expanded to include study of alternative means of cooling.

It is Hydro's view that restrictions and requirements for changes to this cooling arrangement should be based on factual data resulting from such investigational programs. The possible penalties imposed on the citizens and industries of the Province due to unsupported restrictions which lead to inefficient conversion of heat energy into electricity are very large in both capital cost and energy conversion.

There is no wish that other beneficial uses be impaired by utilizing the lakes for cooling purposes. We recognize that an expanding population surrounding the Great Lakes depends on these large interconnected bodies of water for their livelihood and pleasure. However, it is believed that the use of the Great Lakes water by electric utilities for efficient cooling purposes represents a legitimate use and a very important energy resource for the Province of Ontario and that this use is or can be made compatible with, if not enhance, other applications.

Although our present cooling systems appear to have no significant detrimental effect on the ecology of the lake or lake bottom in the area of the warm water discharge, we do not have a fixed position on this arrangement. If investigations show that thermal discharges from our thermal-electric stations do cause significant deterioration of the quality of the aquatic environment of the Great Lakes, appropriate changes will be made.

ii) Heat Rejection Characteristics of Thermal Generating Stations

Nuclear generating stations reject more heat to the cooling water than fossil stations of the same size. For example, a 3400 MW GS rejects approximately 24,900 million BTU/hr at the condenser plus 2,900 million BTU/hr at the moderator. With a temperature drop of $20^{\circ}F$ across the plant, this would require 2,780,000 USGPM of cooling water. A fossil station of the same size rejects approximately 15,500 million BTU/hr of heat which, with a

temperature drop of 20°F across the plant, would require 1,550,000 USGPM of cooling water.

Note that the daily water temperature in the lake varies due to natural causes, without a generating station rejecting heat into it. Figure 1 shows a hydrograph for Lake Ontario observed at Pickering during 1970 at depths of 26 feet and 5 feet.

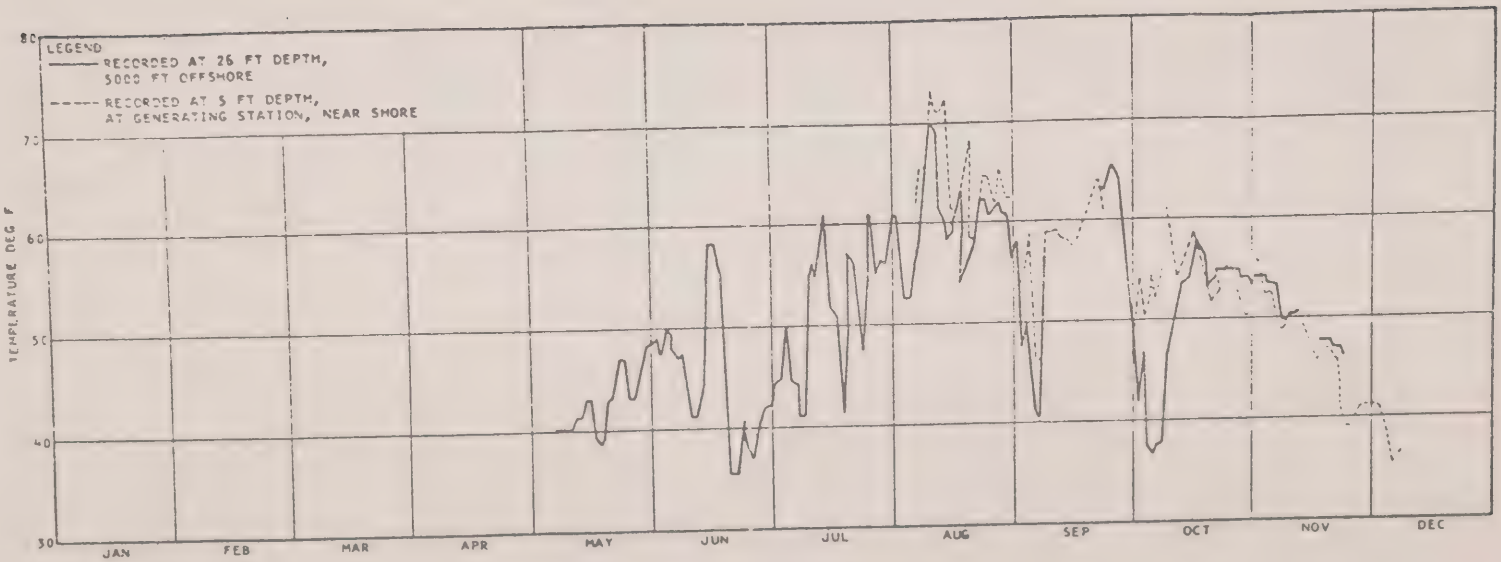
In order to keep the discharge water temperature as well as the temperature rise in the cooling water between plant intake and discharge, within the regulatory agencies guidelines, Ontario Hydro has been using tempering water in some generating stations. This water is taken direct from the cooler intake and mixed with the discharge to reduce the overall return temperature to the lake.

2.2.3.2 Once-Through Offshore Discharge

The broad investigational program undertaken by Ontario Hydro concerning once-through cooling systems includes alternative arrangements for disposal of reject heat, such as offshore outfalls.

A number of conceptual, economic and biologic investigations of offshore discharge systems have recently been completed for a 3400 MW nuclear generating station. The number of variables involved include the distance offshore, the allowed temperature rise, the type of tunnel, type of diffuser, etc.

A cooling water system with a shoreline surface discharge similar to that being designed for our Bruce 'B' GS will cost an estimated 147 million dollars at in-service date (1983). A typical system with an offshore discharge having a concrete-lined tunnel one mile out under the lake with a lake bottom diffuser and having a nominal temperature rise of 20°F would cost approximately 216 million dollars. A similar submerged offshore discharge system without a diffuser would cost 191 million dollars while a two-mile offshore discharge system without a diffuser would cost approximately 232 million dollars. Thus, the additional cost to discharge the warmed water one or two miles further out into the lake is between 44 and 85 million dollars (1983).



Lake Ontario Daily Mean Temperature at Pickering G.S. 1970

Figure 2.2.3.1-1

With respect to the possible adverse biological influences of the thermal discharge itself, an offshore discharge located beyond the littoral zone is preferred to an onshore discharge. However, with regard to entrainment effects, the shoreline discharges are preferred to offshore discharges. The high entrainment, submerged discharges are considered to have a higher overall physical impact on the lake than a shoreline surface discharge.

Many years of operating experience have been obtained with the shoreline discharge of cooling water from large thermal generating stations and there is a growing inventory of environmental data which suggests that the arrangement does not cause significant adverse effects on the aquatic environment. The system maximizes the immediate release of heat to the atmosphere from the water surface layer and minimizes the heat input to the lake. The system has a lower time-temperature effect and lower physical effects on entrained organisms than offshore discharge systems. The system does not cause large unbalanced forces on the lake body such as upwelling or currents as may be the case of offshore dispersal systems.

Observations will continue on existing surface discharge arrangements in the Great Lakes. The expanded program concentrating on alternative types of outfalls will continue, including Hydraulic Model Laboratory studies, and experience elsewhere will be reviewed. Mathematical models of plumes from such outfalls will be developed.

2.2.3.3 Cooling Towers

Cooling towers are structures in which warm water is cooled by the ambient air.

There are many different types of cooling towers in existence but basically a cooling tower is classed as either wet or dry, natural, or mechanical draft. With wet cooling towers, the water is cascaded down through multitudes of suspended strips of packing which expose large surface areas of water to the ambient air. In this type of process most of the cooling actually takes place due to evaporation of some of the water. Dry cooling is the term used when the water is totally contained in coils, thus any cooling achieved is by sensible heat transfer alone. Both of the foregoing cases involve air being heated by water and this leads to continuous

circulation of air due to the buoyancy of the heated air. If a large enclosure with a high outlet is constructed around the water cooling area then the differences in air densities promote substantial air currents. This process is called natural draft. On the other hand if fans are used to induce or force air circulation, the process is called mechanical draft.

Dry cooling towers are extremely expensive both in terms of capital and operating costs. There are very few installations anywhere in the world and those in existence were built on the basis of an extremely limited water makeup supply.

Wet natural draft cooling towers are more expensive than smaller wet mechanical draft towers but they are less liable to interfere with the local environment in the way of icing and fogging, etc. However, the appearance of large natural draft towers and the vapour plume emanating from them raises concerns for aesthetics and also for obscuration of sunlight. For a 3400 MW fossil generating station, the probable arrangement would be 4 x 350 ft high cooling towers. For a similarly sized nuclear station 4 x 500 ft towers would be required.

The location of wet natural draft cooling towers in Ontario would be severely limited by the province's low winter temperatures. A band just north of the Lower Great Lakes might be suitable for their operation, but even there, considerable operating difficulty could be expected.

The operation of cooling towers imposes a penalty against a generating station, as in summer, cooling water temperatures become unavoidably high. This, in turn, gives a higher temperature of steam condensation in the condensers which causes a substantial reduction of plant efficiency and output. There is also a considerable increase in pumping power required.

If natural draft cooling towers were installed at a 3400 MW nuclear generating station, the capital cost would be $181,000,000 (1983) more than a comparable once through system and the capitalized value of 30 years operating costs would amount to a further $276,000,000 (1983). These costs assume that the dissolved solids in the cooling water which do not evaporate can be returned to the natural water

bodies from whence they came. The respective costs for a 3400 MW fossil station would be about half the above.

For a 3400 MW nuclear generating station using high quality make-up water, it can be shown that there will be a continuous summertime make-up requirement of about 170 cubic feet per second (CFS). This make-up is required to replace the 100 CFS lost through evaporation and the 70 CFS of flow which is lost in discarding the dissolved solids from the cooling circuit. A similar fossil station will have a make-up requirement of about 60% of the above nuclear station. A perspective of this water requirement is given by comparing it to the flow of the Thames River at London, Ontario. The average river flow is about 500 CFS while the minimum flow is less than 50 CFS. Thus if a river such as this were to be used as a source of make-up, an extensive water storage pond would be required to compensate for low flows.

2.2.3.4 Cooling Ponds

Cooling ponds are two types; namely, the still pond and the spray pond.

In a still pond, warm inlet water is introduced at one end of the pond and the cold water supply is drawn from the other end. The water is cooled as air contacts the relatively large surface area of the pond. Heat rejection from the pond depends on local conditions such as wind speed, dewpoint, temperature, solar radiation and configuration of the cooling path. Cooling ponds have a low heat transfer rate. This results in very large real estate requirements, in the order of one to two acres per megawatt of installed capacity. For example, a 3400 MW nuclear GS would require approximately 5500-6500 acres of cooling pond surface to dissipate the station rejected heat. The evaporation from a still pond, that is chargeable to a power station, depends upon whether the pond is a natural lake or is constructed specifically for cooling purposes. This is because the additional evaporation from the man-made pond results from both natural causes and from power station cooling. The evaporation from cooling ponds is also highly dependent upon the pond size, the local winds and other atmospheric factors. In general, the additional evaporation caused by the power plant from a natural pond is lower than for either cooling

towers or spray ponds, while that from a man-made pond is higher.

The efficiency of a cooling pond is markedly increased by introducing a spray into the system. In a spray pond, surface evaporation is enhanced by spraying the water through nozzles into the air, where it is separated into small droplets, thus exposing a large total surface area to the air and producing an increased rate of evaporation. As a result, spray ponds have a potential of transferring more heat to the atmosphere for unit surface area than cooling ponds and generally require less than 5% of the total area required for a cooling pond.

The floating modules, in a spray cooling system, are self-contained units generally consisting of a motor-driven, propeller-type pump which distributes the warm water through various types of diffuses. The spray patterns produced are 40 to 50 ft in diameter and 10 to 20 ft high.

A spray canal is similar to a spray pond except that is is more effective and offers more flexibility in location for large installations. For a canal width of 160 ft, a 3400 MW GS would require a canal length of 30,000 to 40,000 ft, depending on the design conditions (cooling water temperature range, condenser intake temperature, etc.) and on the spray module manufacturer design. A 3400 MW fossil GS would require a canal length of 16,000 to 22,000 ft.

One of the disadvantages of spray cooling is the penalty imposed on the efficiency of the generating station. The cooling water operating temperatures are relatively high compared to once-through cooling, especially during the summer. This, in turn, gives higher steam condensate temperature and pressure in the condenser, and the turbine back pressure is increased accordingly causing a loss in power output on turbine cycle efficiency. The increase in turbine heat rate over once-through cooling could be as high as 10%. Another important loss is the pumping power required for the spray modules, which for a 3400 MW nuclear GS could be as high as 32 MW.

Potential environmental problems related to spray systems include: drift of water droplets and vapour from the spray pond or canal, fog formation and icing. There has not been enough experience with large spray cooling systems, especially in winter,

the season of the largest fogging potential. Based upon experience at Dresden Nuclear GS (Commonwealth Edison Co.), it was reported that some light fog (visibilities better than 100 ft) could be expected up to 1000 ft from the spray canal near dawn or on cold winter mornings (temperature less than 10°F). It was also reported that significant drift of water droplets is unlikely to occur at distances greater than 600 ft from a spray canal and that the total volume of drift will not exceed 0.01% of the spray water except during high winds.

Operating problems associated with spray cooling include failure of pump or motor, bearing damage, nozzle plugging and icing on the motors during the winter.

In a spray cooling system, most of the heat is dissipated to the atmosphere by evaporation. The amount of evaporated water for a 3400 MW nuclear GS would be approximately 100 CFS during the summer. Because of this evaporation, the spray cooling system requires blowdown to prevent concentration of dissolved solids. Using high quality make-up water, a 3400 MW nuclear GS would require a blowdown of 70 CFS. To replace the water lost by evaporation and blowdown, the make-up water requirement for the above GS would be 170 CFS. Evaporation, blowdown and make-up water requirements for a similar fossil GS would be 55 to 60% of the above nuclear GS. Again, this can be placed in perspective by comparing it with the flow of the Thames River at London, Ontario which averages about 500 CFS but is less than 50 CFS at low flow.

The estimated increase in capital cost for installing a spray canal system at a 3400 MW nuclear GS over a once-through cooling system is approximately 102 million dollars (1983), not including real estate costs for the spray canal. The estimated increase in present worth value (1983) for the operating costs of the spray canal, capitalized over 30 years life of the station, is approximately 281 million. The estimated increase in total capital and operating costs of a spray canal system over a once-through system for a 3400 MW nuclear GS would, therefore, be 383 million dollars. These costs assume that the dissolved solids in the cooling water which do not evaporate can be returned to the natural water bodies from whence they came. The respective cost increases for a similar fossil station would be approximately 60% of the above costs.

References

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(3) Supplementary Report, Cooling Water Systems for Darlington G.S., Generation Projects Division, August 1975.

(4) Generation Station Condenser Cooling by Cooling Ponds and Spray Canals, O.H. Report No. 75010, February, 1975, Generation Concept Department.

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Line Number

2.2.4 Air Pollution Control

2.2.4.1 Fly Ash Collection

(a) General

The large volumes of gas emitted from utility boilers dictates that collection equipment designed to remove the particulate in the gas stream must also be large. This is further compounded by the fact that the efficient removal of particulate requires low gas velocities in the collection devices. A typical 500 MW pulverized fuel unit burning eastern bituminous coal will produce about 1,400,000 cfm of gas. Electrostatic precipitators are designed for gas velocities of about 6-7' per sec for this coal and even less, say 4' per sec for oil. Bag house filters are usually designed for even slightly lower velocities than this. From this then it is evident that dust collectors are a significant item in the power plant.

Particulate emissions can be controlled by the introduction of a collection device in the flue gas stream at some point between the furnace, where combustion takes place, and the stack, where the flue gases are dispersed to the atmosphere. Collection devices fall into two classes, mechanical and electrical. Mechanical collection devices may be cyclones or bag house filters.

Cyclones direct flue gas flow into a rotational pattern so that the heavier particulate material is separated from the flue gas stream by centrifugal forces. They are, therefore, only efficient at separating relatively large particles and leave the small light particles in the flue gas stream. Typical collection efficiencies are about 70%.

Bag house filters separate particulate matter from the gas stream by passing the gas through a filter cloth in much the same manner as a household vacuum cleaner. These devices, though attaining quite high collection efficiencies of about 99%, again tend to have poorer collection efficiencies with very small particulate sizes, and also suffer significant pressure losses through the filter material,

resulting in increased energy consumption at the fan. They place constraints on the operation of the unit and maintenance costs are high.

Electrical collection devices are all based on the process of electrostatic precipitation, in which a particle is charged electrically and then attracted to a collection surface as it passes through an electrical field. Collection efficiencies can be over 99.5% and unlike the mechanical devices, they are high for very small particulate sizes as well as for large particulate sizes.

The electrical resistivity of the ash particle is one of the major parameters which affects the design of electrostatic precipitators. If the layer of ash which builds up on the collecting plates of the precipitator has a high electrical resistance, a layer of insulation is effectively formed, thus reducing the collecting efficiency of the precipitator. On the other hand, low resistivity ashes rapidly lose their charge after collection and having thus dissipated the attractive force, they tend to re-entrain into the gas stream. Thus there is an optimum range of resistivity for efficient particulate collection. It has been determined that ash resistivity is influenced by the sulphur content of the fuel, the sodium content of the fuel and possibly by the moisture content of the fuel. The ash from high sulphur fuels (greater than 3% sulphur) can be collected easily by electrostatic precipitation, but it tends to re-entrain, making good aerodynamic design of the precipitator very important if the ash is to be retained on the collecting plate. At normal flue gas, temperatures of about 280°F, medium sulphur fuels (1.5% sulphur - 3% sulphur) generally have ash resistivities in the optimum range for efficient precipitation and, therefore, present fewest problems in precipitator design. Low sulphur fuels (less than 1.5% sulphur) may exhibit high ash resistivities if sodium levels are low. This results in poor collection efficiency, if steps are not taken to counter the effect of the high resistivity. Alternative methods of combating high ash resistivity are as follows:

(b) Hot Precipitators

The resistivity of most fly ashes varies with temperature and reaches a maximum at about 300°F, the temperature at which most conventional precipitators operate. At higher or lower temperatures than this, the resistivity generally reduces quite rapidly, so that in the 600°F to 700°F range, ash resistivities are at much lower levels and permit high efficiency collection. The disadvantages of this approach are that the flue gas volumes are much greater at these higher temperatures, requiring a much larger precipitator. Operating conditions at these high temperatures are also more severe, resulting in more difficult design problems. However, a hot precipitator is more versatile and can probably collect the ash from a variety of coals with acceptable efficiency.

(c) Fuel and Gas Conditioning

As indicated previously, high ash resistivity can be attributed to lack of sulphur, sodium or/and moisture in the fuel. It has been demonstrated that, in some instances at least, the addition of sodium to the fuel in the form of sodium carbonate will reduce the resistivity of ash to acceptable levels and permit high efficiency ash collection. It has also been determined that some of the SO_2 produced from the sulphur in the fuel is converted to sulphur trioxide. Some of this sulphur trioxide condenses on the fly ash particle, in the presence of moisture in the flue gas, at about 300°F, to form a layer of sulphuric acid on the fly ash particle, which is conductive and thus lowers the resistivity of the particle. With low sulphur fuels, there is often insufficient sulphur trioxide available in the flue gas stream to maintain low ash resistivities. However, the addition of just a few parts per million of sulphur trioxide gas to the flue gas stream, is sufficient to reduce the resistivity of the ash particle to acceptable levels for efficient fly ash collection. The difficulties of gas conditioning are associated with being able to distribute the very small quantities of sulphur trixide throughout the flue gas stream, in such a manner that all the fly ash particles are treated and efficient collection is

maintained throughout all sections of the precipitator. To our knowledge, there are very few precipitators using sulphur trioxide or sulphuric acid conditioning, which achieve collection efficiencies which would be acceptable to Ontario Hydro.

(d) Enlarged Cold Precipitators

The third alternative is to build a precipitator to operate at the conventional temperature of about 300°F, but sufficiently large that the reduced efficiency caused by the insulating layer of high resistivity ash is overcome by the increased size, so that the desired collection efficiency is achieved. This of course results in increased capital cost and an increased operating cost due to increased power consumption and maintenance. For very high ash resistivities, cold precipitators tend to be larger and consequently more costly than a hot precipitator designed for the same service, although it may have fewer operating problems. Experience to date, with cold precipitators collecting high resistivity ashes, has been limited.

(e) Coal Blending

In the case where both high and low sulphur fuels are available to a utility, a possible alternative is to blend the two fuels, thus reducing the maximum sulphur content of the fuel burned, but maintaining it within the range that is required for optimum ash precipitation. This can require a substantial capital outlay to provide blending equipment capable of producing a satisfactory fuel blend, in terms of consistency of sulphur content, and the operating costs associated with coal handling can increase significantly.

Ontario Hydro's Approach to Particulate Control

Historically, virtually all of Ontario Hydro's coal purchases have been medium sulphur Appalachian coal from the United States and some small quantities of similar Nova Scotian coal. Consequently, all of Ontario Hydro's existing electrostatic precipitators were designed for ash from this coal. In the future, Ontario Hydro expects to supplement these

Appalachian coal supplies with some low sulphur Western Canadian coal having ash that is considerably more difficult to collect. It is expected that up to 4 million tons of this low sulphur coal will be imported into the East System by 1980, and it is intended to blend this coal with the Appalachian coal to achieve sulphur content in the range of 1-1/2 to 1-3/4%. A recent test burn program at Nanticoke and Lambton, though not conclusive, has given a strong indication that the ash can be collected satisfactorily from this blend.

In the West System, the extension to the Thunder Bay Generating Station is being designed to burn lignite and a wide range of alternative coals. These fuels are believed to have a wide range of ash resistivities and hot precipitators have been committed to these units.

The type of precipitators selected for future generating stations burning low sulphur coal will depend upon such factors as the ash resistivity of the design coals and their reliability of supply.

Hydro operates electrostatic precipitators at all its fossil fired generating stations. The precipitators on most coal fired units have design efficiencies of 99.5% or better, whereas those on oil fired units have design efficiencies of 95%. All of these precipitators produce what is essentially a clear plume, except during cold weather conditions when a vapour plume occurs. All operate well within the Provincial regulatory requirements.

2.2.4.2 Control of Sulphur Dioxide

Sulphur dioxide is formed by the oxidation of sulphur in fuel during the combustion process. It thus becomes a constituent of the flue gases which are ultimately emitted to the atmosphere. There are five basic approaches to reducing the effects of sulphur dioxide emissions from generating stations on the environment.

(a) Burn Low Sulphur Fuels

Ontario Hydro has used low sulphur fuels as a means of limiting ground level concentrations of sulphur dioxide under adverse meteorological conditions for a number of years. RL Hearn GS was converted to burn sulphur free natural gas,

as well as coal, in the late 1960s and supplies of low sulphur coal were obtained and stored at Lambton, for use under adverse meteorological conditions. Studies of the feasibility of converting Lakeview to burn either natural gas or low sulphur oil were also made, though neither alternative was adopted, due to the inability to ensure an adequate supply of either fuel. Presently, Hydro is preparing for the delivery of additional quantities of up to 4 million tons of low sulphur Western Canadian coal, which will reduce the average sulphur content of the coal burned by Hydro from about 2.3% to about 1.7%. A contract has also been signed for the purchase of some Petrosar low sulphur residual oil, which will be burned at Lennox GS. The Thunder Bay extension in the West System has been designed to burn low sulphur lignite and the proposed Marmion Lake GS is expected to burn low sulphur Western Canadian coal. It is also planned to convert JC Keith GS to burn low sulphur fuel.

(b) Tall Stacks

Tall stacks improve the dispersion of the flue gases into the atmosphere, signficantly reducing the concentrations of pollutants at ground level. Hydro's commitment to the principle of tall stacks began in the late 1950's, with the construction of the 500 ft stacks at Lakeview. All generating stations built subsequent to Lakeview have stacks exceeding 500 ft in height.

(c) Load Reduction

Sulphur dioxide emissions can be reduced by lowering the load on a given generating station, if adverse meteorological conditions within its vicinity prevent it from meeting the Provincial standards. The loss in generation would have to be made up from other generating stations, operating under less restrictive weather conditions. This technique requires accurate forecasts of adverse meteorological conditions, so that arrangements can be made to transfer load.

Line Number

(d) Fuel Desulphurization

Many processes, designed to reduce the sulphur content in fuels, are presently being developed in various parts of the world. These range from oil desulphurization by hydrogenation to coal gasification, liquefaction, and solvent refining. It appears that existing processes for fuel oil desulphurization and coal gasification are too expensive to make them realistic alternatives to other methods of sulphur dioxide control. Second generation processes, presently being developed are probably about ten years from commitment for commercial application. Ontario Hydro is monitoring the development of these processes and is prepared to actively investigate any which appear to offer significant environmental advantages at acceptable cost.

(e) Flue Gas Desulphurization

Considerable effort by governments, utilities and equipment suppliers, has been devoted to the development of flue gas desulphurization processes for the purpose of reducing the emissions of sulphur dioxide from fossil-fuelled generating stations. However, at this time, flue gas desulphurization has not been developed to the level where full scale systems could be committed, with acceptable risk to new or existing generating stations, for the purpose of reliably meeting air quality criteria. It seems unlikely that any flue gas desulphurization systems will achieve this level of development until the early 1980's at the earliest.

Several systems are now in the process of being demonstrated at a large scale, or have reached the stage of development where a large scale demonstration project might be the appropriate next step. Over seven years after the first full-scale demonstration flue gas desulphurization system was installed on a utility boiler in 1968, there are now only approximately 22 demonstration systems installed in North America, many of them small by utility standards. The installed scrubbing capacity is approximately 3800 MW out of a potential for scrubber application well in excess of 150,000 MW. Many of these scrubbers operate only intermittently.

Line Number

Most flue gas desulphurization processes involve scrubbing or washing of the flue gas. Because of the large volumes of flue gas which must be handled, the equipment is very bulky and expensive. Generally, processes are categorized as "recovery" or "non-recovery" processes Recovery-type processes recover the sulphur from the flue gas in the form of some useful by-product, such as concentrated sulphuric acid or elemental sulphur; non-recovery processes discard large quantities of waste material containing the captured sulphur.

Non-Recovery Processes

The non-recovery processes have accumulated more operating experience, at least on coal-fired boilers. The principal non-recovery processes are the lime and limestone scrubbing processes. In these processes the SO_2 is captured in a recirculated aqueous slurry. Slurry bled from the system is either disposed of directly in a pond or is dewatered to a mud-like sludge, chemically stabilized by the addition of flyash and other additives, and disposed of as landfill.

Initially these processes appeared to be the simplest and least expensive and received a large share of the interest; there were no by-products which required marketing. Several suppliers including Combustion Engineering, Babcock-Wilcox and Chemico, have studied these processes and built prototypes. TVA selected limestone scrubbing for full-scale demonstration at its Widow's Creek Plant. Ontario Hydro's Research Division conducted extensive pilot scale studies of the process. Because of this interest, lime/limestone scrubbing was expected to be the first process to achieve successful development.

The major problems which have been encountered with lime and limestone scrubbing are plugging due to build-ups of sludge and scale in the absorber and entrainment separator, erosion and corrosion due to the recirculating slurry, handling and disposal of the large quantities of waste sludge and drying of the gas plume. As experience with these systems has grown, more problems have been uncovered and their complexity and cost have increased substantially. In addition, dissatisfaction with the magnitude of the waste problem has been increasing. The Ontario Ministry of the Environment has indicated to Ontario

Hydro that it does not consider non-recovery processes desirable, even is satisfactory landfill material could be developed from the waste sludge.

Development progress has been slow, but recently, improved reliability has been reported by some lime/limestone scrubbing installations.

The Chemico/Mitsui carbide lime scrubbing system in Japan is reported to have operated reliably since its start-up in March 1972. Carbide lime is a by-product of the manufacture of acetylene. However, the process is operated "open-loop" which minimizes plugging but releases large quantities of dissolved solids to surface waters. Operating in this manner would generally not be acceptable in Canada.

The Combustion-Engineering Carbide lime scrubbing system at Louisville Gas and Electric's Paddy's Run Station has also reported high availability. Sludge leaves the plant at 60-65% water content and is stabilized by mixing it with dry flyash on an approximately 1.1 dry weight basis at the disposal site. L.G. & E. expect to receive $1.8M from the U.S. EPA for further studies of the process including studies on the aging and leaching properties of the waste, on which there is presently very little information.

A Research-Cottrell limestone scrubbing system installed on a 115MW boiler at Arizona Public Service Company's Cholla Station recently completed 12 months of operation. This station burns coal averaging only 0.5% sulphur content and Research-Cottrell have recognized that the scrubber used would not be suitable in its present form for use with higher sulphur contents. Furthermore, the Cholla scrubber system does not operate "closed loop". There is no sludge treatment; slurry is ponded directly and no pond water is recycled to the system.

Other installations have been less successful. Certainly some progress is evident. Waste disposal in particular still needs considerable development effort.

The double-alkali processes were devised in order to avoid the plugging problems of the lime and limestone slurry scrubbing systems. The flue gas is scrubbed with a clear solution of a highly soluble alkali, such as sodium or ammonia, which is

regenerated outside of the scrubber with lime or limestone to produce a waste sludge similar to that from the lime/limestone systems. It is doubtful that the double-alkali processes offer any overall advantage over the lime/limestone processes.

There are some flue gas desulphurization processes which might be considered recovery or non-recovery, depending on the circumstances. Examples would be those processes capable of producing high quality gypsum (calcium sulphate) such as the Chiyoda, Hitachi, and Lurgi Sulfacid processes. Gypsum is used in the manufacture of some building materials such as lathing, sheathing and wallboard. In Ontario, gypsum is available naturally in large quantities at a high purity and low cost. However, in Japan it is not, and by-product gypsum from flue gas desulphurization plants is reportedly used in the manufacture of building materials. Investigations by Ontario Hydro to date have come to the conclusion that, for the present, such processes must be considered to be non-recovery processes, because of the lack of a similar market for by-product gypsum.

Recovery Processes

The variety of recovery processes under development is more extensive. Generally, the recovery processes are more expensive, and many require significant quantities of power and fuel, including natural gas, and involve handling hydrogen sulphide. They conserve some other resources and avoid the large quantities of waste associated with the recovery processes, but they require the marketing of a by-product. This is of critical importance, since the viability of the process may depend on the reliability of the market for the by-product.

Under some circumstances elemental sulphur may actually be considered to be a waste product. It is, however, a relatively compact and trouble-free one; thus despite the fact that most sulphur is eventually consumed as sulphuric acid, and would be more costly to produce than acid, it might be the preferred product under uncertain market conditions because it is more easily handled, stored, and transported than acid.

The Chemico-Basic Magnesium Oxide Process is a regenerative process (the absorbent is regenerated for recycle to the absorber), which could

theoretically be adopted to produce either elemental sulphur or concentrated sulphuric acid. The first prototype was installed at Boston Edison's oil-fired Mystic 6. During the two year demonstration project which ended in June 1974, the longest continuous run was only seven days. Boston Edison state that they would have "a high level of confidence" in building an improved second generation system, but so far have not committed any further scrubbers to their system. The first coal-fired application of the process was started-up in September, 1973 and is experiencing similar problems.

The Wellman-Lord Process can also produce either elemental sulphur or sulphuric acid. The process is reported to have operated reliably on oil-fired boilers and other applications. The first application to a coal-fired boiler is scheduled to start-up in early 1976 at Northern Indiana Public Service Company's Mitchell station. Development effort is presently directed at minimizing the costly and environmentally difficult 8-10% purge of sodium sulphate which is not regenerated in the process as currently offered.

In the Monsanto Cat-Ox Process sulphur dioxide is catalytically oxidized to sulphur trioxide which is condensed to 78% sulphuric acid. The 100 MW prototype system started-up in September, 1972 on the Illinois Power Company's coal-fired Wood River Unit 4 and has since operated less than 700 hours. The system is presently shutdown indefinitely.

Ammonia scrubbing has been studied by both the Tennessee Valley Authority and Ontario Hydro as a back-up to limestone scrubbing. The equipment involved in the absorption step appears to be relatively trouble-free but a major problem has been the emission of a persistent "blue fume" of very fine ammonium salt particulate. Recently however, some progress has been made on the fume problem. Several approaches to recovery are being investigated for combination with the absorption step. TVA has been pilot-testing one process, and an alternative, the IFP Process, is now being tested on a 35 MW utility boiler in France.

Cost Estimates

The estimated cost of flue gas desulphurization can vary considerably, depending among other things, on the process, unit and station size, capacity factor,

sulphur content of fuel, market conditions for by-products, and whether the application is a new station or retrofit. As an indication, the Tennessee Valley Authority's November 1974 estimate covering several processes is in the range of approximately \$40 - \$60/kw for capital for a new 2000 MW station and total cost estimates are in the range of approximately 3-4 mills/kwhr (capital and operating costs); a later statement by the National Electric Reliability Council quotes \$65-100/kw and possibly higher capital costs and operating costs of 2-5 mills/kwhr. In our opinion, the higher figures in these ranges are likely to apply.

Meeting Provincial Air Quality Standards

By maintaining its existing clean fuel supplies and making use of low sulphur Western Canadian coal, and some low sulphur residual oil, Ontario Hydro can continue to meet the Provincial Air Quality Regulations.

2.2.4.3 Particulate Sulphate

It has recently been recognized that particulate sulphate may be a pollutant and may be a contributing cause of respiratory problems. At this point in time, little is known about the formation of particulate sulphate or its effects on the population.

With specific reference to generating stations, it is known that sulphur trioxide in the flue gas can condense on fly ash particles, to form sulphate on the outer surface of these particles. Some of these fly ash particles, approximately 0.5% of those entering the precipitator on a coal-fired unit are emitted to the atmosphere. Sulphur dioxide in the atmosphere, some of which is emitted by generating stations, is also known to react with other components of the atmosphere to form particulate sulphate and sulphite. At this point in time, however, it is not known how the rate of particulate sulphate formation is affected by the concentration of sulphur dioxide in the atmosphere.

There also seems to be a large gap in knowledge of the effects of particulate sulphates.

Line Number

Research

Ontario Hydro is a member of the Electric Power Research Institute and has representation on a steering committee which directs the research of the institute into sulphate particulates. Hydro has also set up a series of sulphate monitoring stations of its own and has also measured the oxidation rates of sulphur dioxide to sulphur trioxide in some stack plumes. This data will be used as the basis of work to determine the formation mechanism of particulate sulphates.

It is Ontario Hydro's belief that this basic research into the formation mechanism and effects of particulate sulphates must be carried to a point where meaningful conclusions can be made, before any policy for the control of particulate sulphates can be formulated, with any hope of success.

2.2.4.4 Control of Oxides of Nitrogen

Oxides of nitrogen are formed in all high temperature combustion processes, which use air as the oxidant. Atmospheric nitrogen and oxygen combine at high temperatures to form nitric oxide, some of which is further oxidized to nitrogen dioxide in the flue gas stream, so that a mixture of these two oxides of nitrogen is emitted, along with the other flue gases, to the atmosphere. Nitrogen in the fuel may also combine with oxygen during the combustion process to add to the oxides of nitrogen present in the flue gas.

It has been determined that, though it is not possible to prevent the formation of oxides of nitrogen entirely during the combustion process, the rate of formation is dependent on the flame temperature, the amount of excess oxygen available and to some extent, on the rate at which the air and fuel mix in the combustion zone. Boiler manufacturers have developed a number of modifications to their designs, based on these principles, which help to reduce the level of emissions of nitrogen oxides to the atmosphere. These modifications have in general been most successful with gas fired units, moderately successful with oil-fired units, and have had limited success on coal-fired units.

They are:

i) Flue Gas Recirculation

Some of the flue gases are recirculated back into the combustion zone in the boiler, thus increasing the amount of inert gas in the combustion zone and consequently reducing the temperature of the flame.

ii) Overfire Air

Some of the air required for complete combustion of the fuel is excluded from the combustion zone in the boiler and admitted at a level above the combustion zone. Thus, incomplete combustion occurs in the combustion zone, in an atmosphere which has little oxygen available for combination with atmospheric nitrogen. Complete combustion of the fuel then takes place in the region of the overfire air entry, but at reduced temperature, so that nitrogen oxide formation is reduced.

iii) Reduction of Excess Air

Control of the quantity of air admitted to the boiler to be just sufficient for complete combustion of the fuel, reduces the amount of oxygen which is available to combine with nitrogen, and thus limits the formation of nitrogen oxides. Typical values of excess air required for complete combustion are 7% for gas-fired units, 3% to 5% for oil-fired units and 18% to 25% for coal-fired units.

iv) Burner Modification

Burners are modified to reduce the rate of mixing of fuel and air, slowing the combustion process, reducing flame temperature and thus, reducing nitrogen oxide formation.

Meeting Provincial Air Quality Regulations

Provincial regulations presently limit the point of impingement concentration of oxides of nitrogen to 500 micrograms/cubic metre, averaged over half an hour. Hydro presently meets this limit with no difficulty and it is, therefore, difficult to justify large capital investments and equipment outages in attempts to reduce nitrogen oxide emissions, which presently fall well within provincial requirements. Some intermittent brown plume problems may however require corrective action. Hydro has done entensive measurement and

monitoring of its nitrogen oxide emissions in the past and will continue to do so in the future. Discussions have taken place with boiler manufacturers to explore means of supplying boilers designed to minimize the nitrogen oxide production.

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2.2.5 Combined Heat and Power Generation

Combined heat and power generation can result in improved efficiency of energy use compared with independent generation of heat and electricity. The overall cost of heat from such systems is dependent on many things including the fuels used at the power plant and those displaced at the point of heat use. Of particular importance is the capital cost of the heat transmission and distribution systems. This paper discusses some of the considerations for industrial process heat and district heat supply in Ontario.

The Cold-Condensing Power System

In Hydro's modern and efficient steam-electric generating stations, designed and optimized solely to produce electrical energy, steam supplied from a boiler at high temperature and pressure expands through a turbine to low pressure and temperature doing work to drive the electrical generator in the process. The low pressure low temperature exhaust steam leaving the turbine enters the condenser - a large heat exchanger cooled by lake water - where the steam gives up its latent heat of vaporization and is condensed to liquid water.

The condenser is maintained at as low a temperature as possible in order to allow the steam to expand to as low a temperature and pressure as possible, thereby maximizing the amount of work obtained from the steam and increasing the efficiency of the generating station; in fact, the condenser actually operates at a vacuum and the temperature of the exhaust steam is as low as 80°F. The condensed water, which is of very high purity, is pumped back into the high pressure boiler to repeat the cycle. Steam turbine cycles which operate in this manner are described as "cold-condensing".

Although the quantity of latent heat rejected as the steam condenses is large, it is virtually unusable because of the low temperature at which it is available; the temperature of the cooling water leaving the station varies from 54°F in winter to 90°F in the summer.

In Hydro's fossil-fuelled generating stations, designed to produce electrical energy only, typically 38% of the heat supplied by the fuel is made available as electrical energy from the station;

about 10 to 12% of the heat cannot be recovered from the boiler flue gases, and about 50% of the heat supplied by the fuel is discussed to the condenser cooling water. In Hydro's nuclear generating stations, about 30% of the heat released in the reactor is made available as electrical energy from the station and about 68% of the heat is rejected in the condenser cooling water.

Combined Heat and Power Systems

When heat is required for space heating or for use in an industrial process, and is generated directly and independently of electrical power generation, by burning a fuel in an efficient modern boiler, up to 80 to 90% of the heat released from the fuel will be available as useful heat, depending on the boiler efficiency. The remaining heat is lost with the boiler flue gases.

When there are coincident requirements for both heat and electrical power, and the economics are favourable, combined heat and power generation can result in improved overall efficiency of energy use compared with independent generation of heat and electricity.

Back-Pressure Turbine

One approach to combined heat and power generation is the use of a "back-pressure" turbine in which the steam is exhausted from the turbine at high temperature and pressure to supply the heating load. Although the electrical output per unit of fuel input will be reduced compared with expanding the steam to lower pressure and temperature as in a "cold condensing" turbine, the overall efficiency will be substantially higher than with independent generation of heat and power and will approach the efficiency of the boiler because all of the heat in the exhaust steam is usefully applied. In the absence of a heating demand a straight back-pressure turbine may continue to operate at high exhaust pressure if a heat sink is provided but compared with a "cold condensing" turbine is an inefficient method by which to generate electricity only. Back-pressure turbines are usually smaller units sized to supply a particular industrial or district heating load and generating electrical power as a by-product.

Extraction Turbine

A second approach is the "extraction" turbine in which some fraction of the steam flow is extracted from the turbine at a point part way through the turbine; the extracted steam has already done some work to generate electrical power and the heat remaining in the steam is supplied to the heating load. The steam remaining in the turbine is fully expanded to low temperature and pressure and its latent heat is rejected to the condenser cooling water at low temperature as in a conventional, "cold condensing" power station. The overall efficiency of heat and power generation will be proportional to the amount of steam extracted to supply the heating load. The pressure and temperature of the extraction point (or points) are selected in terms of the temperature requirements of the heating load. The turbine generator and condenser can be designed so that when heating is not required the entire steam flow can be fully expanded and the electrical output increased accordingly. Although extraction systems are usually designed into a turbine before it is built, some existing units can be modified to permit extraction.

When extraction steam is taken from an existing turbine generator unit, its electrical output will be reduced as a result and one of the costs of extracting steam will be the capital cost of replacing the lost generating capacity in order to maintain the required generating capacity on the power system. If steam extraction is restricted to off-peak periods only, it may be possible to avoid a portion of this cost penalty. Extraction is generally the more suitable approach for a large utility installation where the primary function is to supply electrical power and process or district heat is a by-product.

Opportunities for Combined Heat and Power Supply

The high cost of transmitting heat is a principal factor in the economics of combined heat and power generation. The relative economy with which electrical power can be transmitted has resulted in the development of very large central generating stations, with their attendant economies of scale, to serve widespread electrical loads. Siting considerations usually require that these stations, whether fossil or nuclear-fuelled, be located outside of the urban areas. Whereas, electrical energy can be transmitted economically over large distances,

transmitting heat via a steam or hot water pipeline is comparatively expensive.

By-Product Electricity

The above conditions would tend to favour a small combined heat and power plant, matched to the heating need, and located at the industrial or district heating load, for the following reasons:

- by-product electrical power could be consumed by the industry or municipality or sold to the utility.

- the interconnection between the industry and utility would be in the form of an electrical power line, which would be present in any case, rather than more expensive heat transmission pipes.

- the heat/power system could be tailored to meet the specific heating needs of an industrial process.

- the siting constraints for the industry or utility with respect to the supply of heat are minimized.

- since the industry is connected to a large power grid rather then a specific power plant, scheduling problems with respect to initial supply of heat and electricity are minimized.

Such plants are likely to burn fossil (or refuse) fuels and use back-pressure turbines.

By-Product Heat

On the other hand, particularly in the event of future shortages of fossil fuels for industry, it may be advantageous to locate industries with large heat demands in industrial parks adjacent to existing or planned nuclear generating stations. This alternative would probably use steam directly from the reactor or from an extraction turbine. In many instances, these features would have to be designed into the generating station and this presents secheduling difficulties for the industry, since the design decision for the station may have to be made 6 to 8 years before heat could be supplied.

District Heating

The application of combined heat and power generation systems to space heating loads through district heating has been practiced in Europe where conditions such as high fuel and power costs and high housing densities have favoured its use. In European practice, typically heat is supplied from smaller fossil-fuelled heat and power units of up to approximately 200 MW(e) capacity and located near the heating load. Combined heat and power plants may constitute up to 50 to 75 per cent of the installed heating capacity on a district heating system with less capital-intensive straight boiler plant serving as peaking and standby capacity. Because of the high capital cost of combined heat and power plants, it is most economical for growth in the heating load to be supplied first using straight boiler plant and for the combined plant to be brought into service only when a heating load has been established of sufficient size to justify the expenditure; at this point the straight boiler plant assumes a role of peaking and standby service.

In Ontario, as already mentioned, siting considerations for both fossil and nuclear-fuelled generating stations generally favour sites located some distance from urban areas. This introduces the necessity for high capital cost heat transmission pipelines if these plants are to supply heat for district heating. An alternative would be small 200 MW(e) plants located in the urban areas, if this were acceptable to the public; this approach would suffer from a loss of economy of scale compared with larger plant. Supplying heat from large generating units, particularly through a single transmission line, would require increased standby heating capacity compared with smaller units located on the district heating system.

Distribution piping systems for district heating are also very expensive. Although work is in progress to develop new materials, experience has shown that protection of buried pipe against corrosion often requires that for sizes greater than 2 to 3 inches, the pipe be suspended in a well drained concrete culvert. When distribution piping is back-fitted into already developed areas, the additional civil work increases costs substantially compared with new development. Because of the high cost of distribution piping networks, high load densities are required for district heating to be economic. In

those areas of Europe served by district heating, the majority of the population live in apartment blocks, rather than single family homes.

The availability of capital for such systems is an important consideration and is claimed to be a major obstacle to further expansion of district heating in Europe.

The load factor of the heating load and the project life are also important economic considerations because of the capital cost-intensive nature of combined heat and power schemes. Forecasting future fuel and power costs over long periods is less than certain.

Ontario Hydro recently contributed to a study on district heating undertaken by the Ministry of Energy. This study is a conceptual one which considers the extraction of steam during the daily off-peak period from the Pickering 'B' generating station, currently under construction, to provide space heating for the proposed North Pickering community. Heat would be stored in hot water contained in large unpressurized tanks for use during the day. This scheme was considered to be the most optimistic one for worthwhile study at this time, involving heat supply from uranium.

In summary, combined heat and power generation has the potential for improved efficiency of energy use and increased energy costs will tend to favour the economics of combined heat and power generation. Consideration of opportunities for combined heat and power generation must recognize many complex and uncertain factors including planning and organization, plant siting constraints, reliability of heat supply, load growth, environmental effects, fossil/nuclear fuel availability, and ultimately, economics, including the availability of capital. Ontario Hydro plans to continue studies directed towards the most promising opportunities for combined heat and power generation.

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2.2.6 Utilization of Heat Rejected to Cooling Water

2.2.6.1 General

Although power stations reject large quantities of 'waste' heat, it does not necessarily follow that useful heat is being wasted. Several factors combine to pose a formidable problem to the utilization of waste heat -- the very large quantities of heat involved, the low temperatures at which it is discharged, the variability of the temperature level, and the difficulty of integrating the two highly complex systems of power generation and heat utilization.

The exhaust steam leaves the turbine at about 80°F and enters a large condenser through which cold water from the lake is pumped. The temperature of the lake water is increased by as much as 20°F in passing through the condenser tubes of a Candu plant. Since lake temperature varies from 34°F in winter to 70°F in summer, the maximum temperature of the heated water being discharged from the condensers, varies from a temperature of 54°F in winter to 90°F in summer.

There are also wide short term variations in the lake temperature. Changing winds can cause variations in excess of 20°F in a 24-hour period. In addition, changes in unit load to meet fluctuating demands for power can alter the temperature rise across some plants by 10°F or more. Thus the temperature of discharged cooling water could vary by as much as 30°F in a single day.

Therefore the number of applications which warrant investigation are rather limited. Some of the possibilities which have been suggested are given below. Of these four items, some experimental development work has been done on the second and third and the other two are at the suggestion stage.

Heating of Buildings
(first stage of a multistage system)
Aquaculture
Agriculture Including Greenhouses
Recreation

2.2.6.2 Space Heating

The temperature of the condenser cooling water leaving Ontario Hydro's thermal generating stations

is as low as 54°F during the winter. At this low temperature, the cooling water is of no direct use for space heating. Schemes have been suggested which make use of the cooling water but require additional energy. For example, a heat pump installation could use the condenser cooling water as a source to produce hot water for district heating. In another scheme which has been suggested, cooling water leaving the condenser could be heated to a higher temperature suitable for space heating by using steam extracted from the generating station. In this scheme, most of the heat is actually supplied by the extracted steam rather than in the condenser.

Section 2.2.5 Combined Heat and Power Generation discusses schemes to supply heat at higher temperatures from generating stations specially designed or modified for this purpose; district heating is also discussed.

2.2.6.3 Aquaculture

The combination of current and warm water not only attracts some fish species into discharge canals but, apparently, has little adverse effect. Such observations have encouraged research on the use of this warm water environment for fish cultures, and it has been found that a controlled, elevated temperature regime can be used to promote rapid, healthy growth.

Fish rearing has its limitations; the main one being that virtually the same amount of heat is dissipated to the water body. The quality of the discharge water would be lowered due to the unused supplementary feed and fish wastes which would lead to oxygen depletion and excessive algae growth. Marketing of the product would be another major problem. Rearing of young fish for stocking purposes is a constructive use of discharge water, but the volume of water required would be so small that this use cannot be considered as a solution to the problem.

2.2.6.4 Agriculture Uses of Thermal Discharges

In 1973, Ontario Hydro, in co-operation with Atomic Energy of Canada Limited, The Ontario Ministry of Agriculture and Food, and Agriculture Canada, commissioned Guelph University to evaluate the technical and economical potential for utilization

of thermal discharges in Ontario for agricultural purposes. Further objectives were to study greenhouse heating and soil warming in detail for production of high value horticultural crops, and to consider possible impacts on regional and local economies. Some of the results of this study are:

(1) The use of condenser cooling water in a closed exchange system would not be economically feasible.

(2) The feasibility of using waste heat becomes progressively more attractive as fuel costs and the price of vegetables increase.

(3) The area of greenhouses in Ontario in 1972 (350 acres) could be safely tripled before exceeding the current local market demand. Greenhouses would have to be located adjacent to the generating station.

(4) The use of a possible source of heat from the heavy water moderator cooling water effluent at 140^{o}F could be much more economically attractive but is highly dependent on the distance between the generating station and the greenhouse.

(5) With a contact exchange heating system, using the normal thermal discharge, adequate temperatures could be maintained in Ontario for tomato production between April and November and for cool temperature crops, such as lettuce, during the winter months.

(6) Open-field soil warming in Ontario may advance crop maturity by one or two weeks and could increase yields by 30-40% or more. Although a number of fresh market vegetables appear to have some economic potential, the most attractive appears to be the production of specialized crops such as tomato transplants.

Neither of these alternatives would use a significant portion of the total waste heat. However, more practical operating information is needed, and should be obtained as resources become available to undertake the work. Ontario Hydro is presently initiating a study on the possible use of moderator cooling water effluent as a source of heat for greenhouses.

2.2.6.5 Recreational Uses

The use of discharge water to create a warming effect for public beaches where water temperatures normally are too low for swimming has been suggested. The plan generally envisages some overall area development including parks and beaches.

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2.2.7 Remote Community Power Generation

2.2.7.1 General

The supply of power to remote communities involves either the extension of a transmission line to the community or the provision of an on-site power generation facility. For small remote communities any method adopted will provide power at a considerably higher cost than power delivered to more accessible and densely populated areas because of either the long length of transmission line required or the higher fuel, transportation and maintenance cost associated with a remote facility. For example, an Ontario Hydro estimate of the cost of supplying the 300 kw load in Armstrong, Ontario with a diesel installation was 12 cents/kwhr (1974$), as compared with a current retail cost of 1.8 cents/kwhr in Toronto. A recent ORF study (1) of wind power estimated energy cost of 35 - 38 cents/kwhr for the supply of power at telecommunications sites at Landsdowne House or Big Trout Lake with either diesel or wind/diesel hydrid installations. Naturally costs are a function of the size of the community and its location, but it is evident that power supply in remote communities has its own peculiar set of economics.

2.2.7.2 Diesel Engines

In the size range applicable to many remote communities the diesel engine offers the best combination of efficiency, maintenance and capital cost, and is usually used for this service. Ontario Hydro presently operates these 125 kw diesel engines to supply power to a remote community of approximately 25 homes.

2.2.7.3 Gas Turbines

Lower efficiency, higher maintenance cost, higher noise levels and lower reliability, make gas turbines less popular for the provision of electric power in remote areas. The use of gas turbines as drives for gas pipeline pumping stations is very widespread. In this remote application the turbines have a supply of first class fuel and operate at very high load factors, both of which reduce maintenance.

2.2.7.4 Wind Turbines

Because they would be competing with (or supplementing) high fuel cost alternatives, large wind turbines may become competitive as fossil fuel savers in remote communities. Wind turbines in a suitable size range (100 kw or more) are not commercially available, but experimental units of this size are undergoing testing.

A recent ORF study (1) prepared for the Ontario Ministry of Energy on Wind Power for remote community supplies, estimated that commercially available 6 kw wind turbine units operated in a fuel saver mode in conjunction with a diesel generator could produce power competitive with diesel generator power costs of 35 - 38 cents/kwhr at a remote telecommunications site with seasonally variable, but continuous load and an average wind speed of 13.4 mph.

Because of the high cost of competing alternatives, wind power may prove to be economic in provision of power in remote centres, if turbines of a suitable size are developed.

References

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2.2.8 Status of Energy Storage Technology

Energy is stored in such primary forms as fuel in coal piles or oil in storage tanks, and as potential energy in water collected behind a dam. Storage of converted energy such as heat or electricity is an attractive alternative only when the demand for energy varies periodically with time and it is less economical to match this demand directly with primary energy conversion facilities than to match part of the variable demand with an energy storage system. Such a situation appears likely to emerge with developing nuclear generation programs. As increasing nuclear capacity is added to the generation system, this base load source of energy may eventually be in excess of system energy demand for some parts of the day during some parts of the year. This will necessitate either load cycling the nuclear units or the utilization of suitable storage facilities to receive nuclear energy during off-peak periods and return it to the system during peak periods. This will allow the units to continue to operate on non-cycling base load.

When comparing various energy storage facilities, the factors which are important are capital costs, reliability or dependability, input-output efficiency, storage density and practical storage duration. Some types of storage that have been proposed as possible candidates for use with nuclear generation are described below. For further information, see reference (1).

2.2.8.1 Aboveground Pumped Storage

This is the only developed large scale energy storage concept. It utilizes the ability of an elevated mass of water to produce energy as it flows to a lower elevation. Excess electric energy is used to drive the motors of large pumps which lift the water to the higher elevation storage reservoir. When there is a demand for energy, the water is released to a lower reservoir and generates electricity by the conventional means of a hydraulic turbine-generator.

The stored energy can be held for long periods of time since losses from the upper reservoir are mainly the result of the slow processes of evaporation and leakage. Storage densities are dependent on the elevation difference between the upper and lower reservoirs and are comparatively low. Storage of

significant amounts of energy therefore requires large volumes of stored water.

Generally, the pump and turbine use the same impeller which is connected to a reversible motor-generator. The input-output efficiency is normally between 65 to 70 percent. Operating compatability of such facilities with electric power systems has been demonstrated to be reasonably good. They have the ability to act as spinning reserve and a response for changing from pumping mode to generation measured in minutes.

The major limitation is the limited number of suitable sites having the required topography and land area. Many such systems are in operation around the world including Ontario Hydro's Sir Adam Beck Pumping/Generating Station on the Niagara River. Aboveground hydraulic pumped storage sites available for development in Ontario are few in number. A number of potential sites have been studied by Ontario Hydro in the last 10 years.

2.2.8.2 Underground Pumped Storage

Underground hydraulic pumped storage uses the same working principal as aboveground hydraulic pumped storage. The distinction is in the position of the respective reservoirs. The underground concept essentially exchanges the topographical constraint for a geological constraint, which, in southern Ontario, may facilitate siting. Only one reservoir is required at the surface. The lower reservoir is excavated below ground. When located near an existing large water body, such as Lake Ontario, only the headworks, control room, transformers, switchyard and vent shaft muffler would be visible at the surface. Storage capacity is determined by the excavated volume of the lower reservoir rather than the capacity of the upper reservoir.

The lower reservoir can be located at a depth limited only by available pumps and turbines. This results in increased storage density as well as improved turbine efficiency. Capital costs are predominately excavation costs for the underground works including the lower reservoir, powerhouse, transformer gallery, access and vent shafts. The freedom to select sites closer to major load centres would result in savings for transmission facilities in comparison with some other storage systems. General Public Utilities (New Jersey) is conducting a detailed investigation of a

1000 MWe installation at Mount Hope, and a European utility is studying the possibility of using a limestone mine for the installation of a storage system. Ontario Hydro has received a consultant's report on feasibility and cost of installing such a system in Southern Ontario (see reference (2)).

2.2.8.3 Feedwater Storage

Efficient turbine operation in conventional steam stations requires steam extraction from various turbine stages for boiler feedwater preheating. Feedwater storage involves the extraction of more steam during off-peak periods to heat additional feedwater which would then be stored and used during periods of peak demand. Steam extraction is thus eliminated during these peak demand periods resulting in increased power output. This scheme was first proposed in reference (3).

Because of the high pressure, storage of the large amounts of feedwater required for 8 hours or more, in conventional steel pressure vessels, would be very expensive. The concept under investigation by Ontario Hydro involves the storage of feedwater in tanks located in large underground caverns which have been pressurized with air to balance the water pressure in the tanks. The open tanks would thus be designed only to hold water.

Conceptual studies, so far, have indicated that this system shows promise of technical and economic feasibility. Considerable detailed design and development work is required before a demonstration project could be committed.

2.2.8.4 Steam Storage

This concept provides a method of storing the thermal energy available in excess primary steam from a nuclear generating plant. The steam is extracted from the nuclear boilers during periods of reduced system power demand and condensed at high pressure to provide a supply of hot water. The hot water is then stored in large tanks located underground in pressurized excavated caverns in a manner similar to that described above for feedwater storage. During peak power demand periods the hot water is discharged through a series of flash tanks. The steam thus produced is used to power a special peaking turbine-generator with its own condenser.

In addition to the development needs of the storage cavern; which are similar to those required for feedwater storage, the design and development of high pressure ancillary equipment including the special peaking turbine is required. A small aboveground high temperature heat storage system was used in Berlin before World War II. Both above and underground systems have been proposed more recently (4)(5). The system being studies by Ontario Hydro has some features of each of these.

2.2.8.5 Underground Air Storage

With conventional combustion turbine-generator sets only about one third of the turbine output power is used to generate electricity as approximately two thirds is consumed in driving the air compressor that feeds the turbine combustion chambers. Most proposed air storage schemes, including the only installation committed for construction to date, use excess off-peak electricity to compress air which is subsequently cooled and stored in an excavated underground reservoir. Later this high pressure air is released to the combustion turbine to burn high grade fossil fuel and generate electricity at approximately three times the specific output of the conventional arrangement. Although capital costs for such schemes are comparatively small, this is offset by high operating and fuelling costs.

An alternative scheme using compressed air has been proposed which interposes a regenerative heat storage reservoir between the compressor and the air storage cavern. This would allow the heat of compression to be conserved during the charging period and added back to the air for the generation period. With the hot air supply, the turbine would need less fuel and although capital costs are increased by inclusion of a heat storage reservoir, operating costs are greatly reduced.

There is presently no air storage scheme in operation. The first installation, scheduled for in-service in 1977, is under construction at Bremen in Germany (see reference (6)). This installation has the advantage that the caverns are constructed in a salt dome which provides an air tight geological structure, which is an important and necessary feature of such installations.

2.2.8.6 Hydrogen Storage

Conversion of excess nuclear energy to storable synthetic hydrogen fuel is an often proposed concept for energy storage. Electrolysis appears as the only presently viable means of hydrogen production from CANDU nuclear reactors. Proposed thermochemical production methods require temperatures ($650^{\circ}C$) beyond the capability of CANDU to be more competitive than electrolysis (7). Present electrolysers are 70 to 75 percent efficient (electrical energy to hydrogen energy efficiency) and the hydrogen produced cannot compete economically with conventional fuels. It is generally felt that electrolysers could be developed that are 120 percent efficient (electric energy to hydrogen energy) and if powered by a dedicated electric generating plant could produce hydrogen energy as cheaply as electric energy. It is unlikely, however, that hydrogen produced by off-peak energy would be as economic. If, after storage, the hydrogen needed to be converted back to electricity, the storage scheme could not compete with other methods of electric energy storage.

2.2.8.7 Flywheels

Energy can be stored in the form of high speed rotation of a flywheel. Off-peak electrical power would be used to increase the speed of rotation of a heavy disk to high speed. When power was required to meet system peaks the disk would be coupled to a generator to deliver the energy stored in its rotation. Because of the limited energy that can be stored in a single flywheel (possibly 100 MWh per 300 ton flywheel), large scale energy storage would require significant numbers of the machines.

Friction losses introduced in bearings and windage losses caused by imperfect seals must be minimized. In large flywheels, imperfections in materials will be magnified due to cycling stresses resulting from repeated charging and discharging. This reduces design materials strengths, and the amount of energy that could be stored per pound of material, to values well below those otherwise theoretically attainable in a laboratory. A flywheel failure would produce explosive energy which would require containment, possibly in an underground chamber, for safety reasons. Other problems relate to cost and the development of large variable speed motor/generators and the associated control equipment.

2.2.8.8 Batteries

Batteries may offer advantages over other competing forms of energy storage since they can be dispersed throughout a network and would enable transmission line cost savings to be realized; there are possible system control advantages associated with batteries; and they have a rapid start-up and turnaround time.

However, present day batteries, such as the lead acid battery, have relatively short life time and are uneconomical for large scale installation in a power system. Several battery systems are being researched which may produce more suitable designs by the late 1980's. Ontario Hydro is currently conducting a state-of-the-art study of these systems to determine the prospects for their future application in the Ontario Hydro System.

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2.2.9 Emergent Systems For Power Generation

2.2.9.1 Solar

Generation of electricity from dispersed low intensity solar radiation has been proposed by two distinct approaches; generation of bulk electrical energy at central generating facilities and dispersed local generation. The first approach generally prescribes the use of solar-thermal conversion by means of large arrays of independently steerable mirrors reflecting the direct component of solar radiation to an elevated boiler. Steam raised in the boiler is then piped to a conventional steam turbine-generator. Such systems appear most practical for development in areas of high annual direct solar radiation such as the Southwestern United States where land areas of one square mile appear sufficient to generate 100 MWe of electrical output. A similar land area in Ontario would support about 30 MWe average annual output. Energy storage in Ontario to compensate for reduced solar radiation during wintertime high energy demand period, cloud cover, and darkness, would be considerably more extensive than in the southwestern United States.

Bulk power generation from central facilities using photovoltaic cells has also been suggested, but dispersed application at the load centre is generally considered more practical and compatible with the nature of solar radiation. Both methods are costly and uneconomical by todays standards. For application in Ontario, photovoltaic cells have the advantage of using both the direct and diffuse or scattered radiation and, if capital costs can be reduced from present values of about 20,000 $/KWe by a factor of 10 or more, and if a more economic form of electrical storage becomes available, some portion of domestic electric supply may be generated by this clean, quiet energy conversion device.

Solar energy in Ontario for application to electric generation is reviewed in reference (1).

2.2.9.2 Wind

Wind power has been used in the past to pump water, grind grain and supply electrical power to agricultural communities and isolated farms. In the U.S. prior to 1950, it has been estimated that there were as many as 50,000 windmills generating electrical power at remote farms in the mid-west.

The energy crisis has resulted in a revival of interest in windmills. The major obstacles to the application of wind power on a large scale are high capital costs and high maintenance and equipment replacement costs; the variability in the wind, requiring either a back-up, or a storage system; and the dispersed nature of the wind. Most experts agree that wind power applications will be limited to areas with exceptionally strong winds or to remote communities dependent upon high cost fuels.

To avoid interference of wind current between windmills, it has been claimed that the windmills must be spaced approximately 30 diameters apart (see reference (2)) and this limits the amount of power which could be extracted from a given land area. For example, with wind speeds typical of Southern Ontario, an array of windmills spread over the entire Southern Ontario land mass west of a line between Toronto and Midland, would generate only as much energy per year as the four units at the Pickering Generating Station. A back-up generating station or a very large energy storage system would be required to provide power on demand.

Although currently commercially available wind generators cannot produce power at prices comparable to Hydro's retail costs some individuals may choose to install windmills to supply a portion of their own load either for reasons other than economics or by constructing a unit at low material cost as a hobby.

The use and future potential of windpower is reviewed in reference (3).

2.2.9.3 Magnetohydrodynamics (MHD)

When a gas is raised to a very high temperature (greater than $4500^{\circ}F$) and an alkali metal 'seed' is added to it, the resulting mixture is capable of conducting electricity. In a conventional generator, a copper conductor is passed through a high magnetic field and an electrical current is produced. In magnetohydrodynamics, a conducting mixture takes the place of the copper conductor. When this mixture is expanded at high velocity through an intense magnetic field, an electrical current is produced which can be removed by electrodes placed on the generator walls. After expansion in an MHD generator, the heat remaining in the exhaust gases (which are still at $3600^{\circ}F$) is available to preheat air and fuel entering the MHD combustor and to raise steam in a conventional steam cycle.

MHD is claimed to lessen the problems of high temperature materials because it employs no rotating parts. However, very high temperatures are necessary to obtain sufficient electrical conductivity in the gas to achieve high efficiency. These temperatures coupled with the corrosive effects of the alkali 'seed' and the combustion products, and the need to extract electrical energy at low voltage and high current in this atmosphere, make the problem of finding adequate materials much more severe than in generating methods employed to date.

The major problems facing MHD are:

i) It has not yet been demonstrated that the MHD generator performance necessary to give commercially viable efficiencies (in the neighbourhood of 50%) are obtainable in practice.

ii) The material problems encountered in withstanding the corrosive high temperature gases and large currents must be overcome to provide acceptable performance, lifetime and reliability.

These problems are strongly linked since the efficiency obtainable with MHD increases rapidly with increasing temperature but the material problems encountered are much more severe at higher temperatures. For this reason, the feasibility of MHD hinge more on the solution of the material problems under conditions capable of producing high efficiency than on any other single factor.

The competitive position of MHD with respect to other high efficiency methods of generating electrical power (i.e. advanced gas turbines or potassium turbines) would be enhanced if it could burn coal directly. Once again, however, this may not be possible because of the severe material problems resulting from the corrosive and erosive effect of sulphur, seed, slag and ash in the duct, preheaters, and steam bottoming plant. In view of the competition from advanced gas turbines, it is probable that MHD would have to combine direct coal firing with high efficiency in order to be successful. MHD technology is at an early stage of development and is unlikely to be commercially available before 1995.

In our view, predictions of future practicality cannot be made with any degree of certainty at this time in view of the formidable material problems. For further information see reference (4).

2.2.9.4 Biomass

Growing plants consist mainly of water and hydrocarbons. These hydrocarbons can be used as fuel and indeed, ever since the discovery of fire and the use of flint, the fuel value of trees has been well recognized.

Trees convert a renewable energy source, namely sunlight, into a potential fuel and the use of trees to replace fossil fuel in a fossil-fuel fired power station has therefore been proposed. While such a system is certainly technically feasible, the cost of the systems, the environmental and aesthetic implications, the alternative uses of wood fibres, and land use in general must all be considered.

Forestry based industries such as the timber and pump and paper industries have already predicted wood shortages by the year 2000 and there is an implication that not only are suitable tracts of land not available for plantation but that there are potentially more valuable uses for wood in the economy than burning it to produce electricity.

Existing hardwood forests are relatively slow growing and it has been estimated that as much as 16,000 square miles of such forests would be required to produce the same amount of electrical energy as that from a 1000 MWe nuclear plant at 70% capacity factor.

16,000 square miles is the approximate total land area of Southern Ontario west of a line between Toronto and Midland.

There are however some fast growing species such as aspen - poplar which are being developed for high quantity cellulose production. Such species, which may allow a crop of trees to be harvested every 9 years, if planted on a highly suitable, cultivated land could possibly reduce the land area requirements to support a 1000 MWe generating station to under 1,600 square miles. Although further reductions have been projected by some researchers, it is still true that vast areas would be required to provide fuel for the 10,000 MW of fossil-fired generation equipment either already installed or being constructed in Ontario.

The real estate value of land and its value for other uses, would be critical factors in considering dedicated plantation on a significant scale.

In addition the cutting and delivery of wood to generating stations and its preparation for combustion in special boilers would result in costs that are at least as high as those for coal.

2.2.9.5 Geothermal

The interior of the earth is extremely hot, but the heat is generally too deep to be economically recoverable. In some areas of the world, however recent volcanism or shifting in the earth's crust has resulted in zones of above normal temperature and heat flow that lie close to the surface.

The major types of potentially exploitable geothermal resources are: hydrothermal, where water or steam convection currents transport heat from a deep source to drill hole depth; geopressure, where hot water is trapped under a sedimentary basin of undercompacted sand or clay and carries a large portion of the overburden weight; hot dry rock; and molten magma.

So far, only high quality hydrothermal resources have been tapped. Large scale exploitation of alternative geothermal resource is not envisioned before the year 2000.

Known hydrothermal sources are located in California (Geysers), Wyoming (Yellowstone), Italy, Japan, Iceland, Mexico and New Zealand. Hot dry rock is known to exist along most of the Pacific west coast of North America. Geopressure sources are known to exist in the U.S. along the northern Gulf of Mexico, the Gulf coast and in Wyoming (see reference (6)). Exploitation of the very deep geothermal resources in other less favoured locations, such as Ontario, may never be viable and will be dependent upon results of experience elsewhere.

2.2.9.6 Fusion

When two heavy hydrogen atoms fuse together to form tritium, a very large amount of energy is released.

The earth is dependent on this fusion reaction which is responsible for the vast quantities of energy geing released by the sun. In an attempt to achieve controlled fusion reaction, a number of major

laboratory experiments are being conducted by various U.S. research agencies and other agencies elsewhere.

The basic fuel for a fusion reactor is deuterium, contained in the familiar heavy water currently used to cool and moderate Candu reactors. Deuterium, a harmless non-toxic substance, is found in all the waters of the world and could potentially provide an inexhaustible energy supply. Early demonstration units will probably use a mixture of deuterium and lithium.

Researchers are optimistic that a controlled nuclear fusion reaction can be achieved in the laboratory with 5 to 10 years. There are a number of problems in extrapolating laboratory design to commercial availability and it is considered unlikely that a full-scale electrical power demonstration unit could be committed within the twentieth century.

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